KEVIN PETERSEN

STATE REPRESENTATIVE

Testimony on Assembly Bill 470

Good morning members of the Assembly Committee on Energy and Utilities, thank you for allowing me to testify today on Assembly Bill 470. I have several things to discuss, but I'd like to highlight the three main things this bill will do when signed into law: It will keep the state of Wisconsin's authority over its own power grid, ensure the continued reliability of our grid, and enshrine cost competition into our statutes.

In Wisconsin, when we turn our light switches on at night, we trust that there will be power to light our homes. We value the reliability of our energy, and our energy policies have been made to ensure we have power when we need it. But it wasn't always that way in the state.

A little over 20 years ago, Wisconsin's economic future was in doubt because we lacked a reliable and robust energy grid. Multiple utilities operated a fragmented transmission network. Utilities were disincentivized from making investments in their own transmission because those investments could benefit competitors at the expense of their own ratepayers. This resulted in under investment in transmission causing Wisconsin to be cut off from cheaper external power sources, while decreasing reliability and economic efficiency.

That changed in the late 1990s, when the Governor and Legislature engaged in a multi-session bipartisan effort to make sure that Wisconsin had a safe, reliable, and economically efficient transmission network. Beginning with 1997 Wisconsin Act 240, the state began the process of encouraging utilities to divest their transmission lines in order to consolidate transmission operations in the state. While some utilities retained their transmission lines, such as Xcel and Dairyland Power Cooperative, many other utilities chose to divest these lines. The next session, 1999 Wisconsin Act 9 created the company we know today as American Transmission Company (ATC).

In that act, Wisconsin utilities were permitted to transfer their transmission assets, and ATC was required to assume those assets, along with the statutory duty to provide transmission and maintain the transmission lines that had been transferred. With the state's creation of ATC, much of Wisconsin's transmission lines came under the control of one company whose sole purpose is to ensure the reliable transmission of power in our state.

For many years after its creation, ATC was responsible for the construction, maintenance, and operation of both inter-state transmission projects (such as lines bringing wind power from the Dakotas into Wisconsin) and intra-state projects affecting only Wisconsin's grid. Federal law, at the time, granted ATC and other transmission operators a right-of-first refusal for the construction of these lines, and the projects were overseen and regulated by our own Public Service Commission (PSC).

STATE CAPITOL: POST OFFICE BOX 8953 • MADISON, WISCONSIN 53708-8953

(608) 266-3794 • TOLL-FREE: (888) 947-0040 • FAX: (608) 282-3640 • Rep.Petersen@legis.wi.gov

Unfortunately, since then, an order from the Federal Energy Regulatory Commission (FERC) has undermined states' energy independence, including in Wisconsin, by requiring inter-state projects to go through a lengthy bureaucratic bidding process mandated by the federal government. In 2015, FERC issued Order 1000, which removed a federal right-of-first refusal for incumbent transmission companies to construct inter-state transmission lines, although in Wisconsin, transmission companies retain the exclusive right to intra-state transmission construction.

FERC Order 1000 gives the Midcontinent Independent System Operator (MISO), the Midwest's regional grid regulator and a private entity, the authority to make decisions about Wisconsin's electric transmission lines and power grid that would otherwise be under the jurisdiction of the PSC of Wisconsin. The Order also has the effect of encouraging non-Wisconsin companies to get involved in our state's power grid, even if those companies have not proven they can be reliable in their construction, operation and maintenance of transmission lines.

The goals of Order 1000 were to encourage competition and cost-savings. Although these goals were admirable, unfortunately, they have not necessarily been realized.

When we talk about energy policy, it's important to keep in mind that we're dealing with a highly regulated industry, and it's highly regulated because the legislature intended for it to be that way. I'll use the example of buying something at Wal-Mart to illustrate a point I'd like to make. If I go to Wal-Mart and want to buy a microwave, I go to the microwave aisle and choose if I want the cheap microwave, the expensive microwave, or one of the many microwaves in between. As you're obviously aware, I can't go to an aisle in Wal-Mart to buy my power. In fact, I can't even choose which company I buy my power from.

This is by design. I have one utility that I can buy my power from when I'm at home, and in Wisconsin, I will always have one utility that I can buy power from, even in the most remote corner of Waupaca County. That utility has a regional monopoly on power. In exchange for that monopoly, given to them by state law, that utility is obligated to provide power to every household in their territory, whether they want to or not, and they are subject to extensive oversight by the PSC. Everyone who wants power has access to power. That's known as the regulatory compact.

Given the highly regulated nature of energy policy, it's not surprising that Order 1000's goals of a competitive energy market have encountered challenges. Recent studies have found a number of issues with competitively bid projects under Order 1000. I will go over some of these issues, although it is a non-exhaustive list.

STATE CAPITOL: POST OFFICE BOX 8953 • MADISON, WISCONSIN 53708-8953
(608) 266-3794 • TOLL-FREE: (888) 947-0040 • FAX: (608) 282-3640 • Rep.Petersen@legis.wi.gov

KEVIN PETERSEN
STATE REPRESENTATIVE

First, competitive projects have experienced delays in start times. These delays can be attributed to a number of factors stemming from Order 1000, including the extensive bidding process required by MISO and companies operating in states they have little to no experience in.

Second, the people approving transmission projects are not from Wisconsin. No disrespect to them, but I think you and I have Wisconsin's best interests in mind, and we should be making these important decisions. Without a state right-of-first-refusal, MISO is the one making the decision about who, where, and how transmission lines will be constructed in Wisconsin. The people making decisions about Wisconsin's grid are not beholden to anyone in our state government for the cost, reliability, or efficiency of our power grid.

Third, competitive projects have seen cost overruns on projects that were initially underbid. Even though competitive bidding may result in an initial low-ball bid from a developer, these projects will often have cost-overrun contingencies and multiple exclusions in capped costs. Developers have found ways to game the competitive bidding system by submitting a low-ball bid and then recovering the true costs from rate payers by taking advantage of these contingencies and cost caps. Examples of these cost overruns include the Harry Allen to Eldorado line, which had a cost cap overrun of 39%, the Suncrest Project, which had a cost cap overrun of 14%, and the Ten West Link Project, which is still ongoing and has reported at least a 61% cost cap overrun.

In light of these issues with Order 1000, Wisconsin must take action to return to earlier transmission policy that worked so well in in the 2000s and early 2010s.

Although FERC Order 1000 removed the federal right-of-first refusal, states may still implement a right-of-first refusal. While MISO has authority over inter-state transmission, MISO defers to state law regarding siting and permitting of transmission facilities. Because of this, a state level right-of-first refusal is still permitted and recognized, and such a law will return the authority over transmission lines in Wisconsin back to our PSC.

That is the purpose of Assembly Bill 470:

- It preserves the role of the PSC, whose members are appointed by the Governor and confirmed with the advice and consent of the State Senate, in deciding who owns and operates the transmission infrastructure in the state versus an out-of-state regulator.
- It also requires Wisconsin's transmission developers to competitively bid the construction of their infrastructure which will be reviewed and approved by the PSC in an open, transparent process.

Eight states within MISO have already adopted similar legislation: Texas, Indiana, North Dakota, South Dakota, Minnesota, Iowa, Mississippi, and Michigan. Opponents will talk about how one Supreme Court has overturned this legislation on its merits, which is true, but they

STATE CAPITOL: POST OFFICE BOX 8953 • MADISON, WISCONSIN 53708-8953
(608) 266-3794 • TOLL-FREE: (888) 947-0040 • FAX: (608) 282-3640 • Rep.Petersen@legis.wi.gov

KEVIN PETERSEN
STATE REPRESENTATIVE

won't talk about the other states where the legislation is still good law. Nor will they talk about the wide conservative majorities that passed the legislation, and the bipartisan list of Governors that have signed it into law, including Greg Abbott, Gretchen Whitmer, and Mike Pence. Wisconsin should join these states by keeping our authority over our own power grid and remaining competitive in keeping the price of transmission low.

Decisions about our power grid in Wisconsin should be made by our own state government, not an out-of-state regional authority. The companies building our power grid should be the same companies we've entrusted to keep our lights on at night, not out-of-state or international corporations. Reliable power is critical to the safety and economic well-being of Wisconsin.

STATE CAPITOL: POST OFFICE BOX 8953 • MADISON, WISCONSIN 53708-8953
(608) 266-3794 • TOLL-FREE: (888) 947-0040 • FAX: (608) 282-3640 • Rep.Petersen@legis.wi.gov

JULIAN BRADLEY
WISCONSIN STATE SENATOR

Assembly Bill 470
Assembly Committee on Energy
Tuesday, October 10, 2023

Chairman Steffen and committee members,

We are all likely guilty of taking the availability of power in Wisconsin for granted. But without it families and businesses could not function. Maintaining the efficient delivery of power should be a top priority for both regulated utilities and policymakers here in the legislature and at the Public Service Commission.

Since the Federal Energy Regulatory Commission (FERC) rolled back a federal Right-of-First-Refusal for some types of transmission projects in 2011, several states within the Midcontinent Independent System Operator (MISO) region have passed bipartisan laws to ensure the continued availability of power to consumers. This legislation has been passed by Republican legislatures with overwhelming bipartisan support in Texas, Mississippi, Indiana, Michigan, Iowa, North Dakota, and South Dakota and signed by Republican Governors like Kim Reynolds in Iowa, Greg Abbott in Texas and former Vice-President Pence in Indiana.

These legislative leaders and governors were seeking to retain state level control of their transmission projects and to ensure that their constituents had access to safe, reliable and affordable energy. These same goals are what led Representative Petersen and me to work on the bill before us today.

By proactively establishing a state level Right-of-First-Refusal like so many of our neighboring states we can achieve these goals. We likely have a long day ahead of us, and many regional and national experts available to discuss this is in great detail so I will focus the rest of my testimony on explaining in layman's terms the benefits of this bill.

First, if given the choice between Wisconsin regulators and policy makers and a federal procurement process, I think it should be an easy choice for us to entrust critical energy infrastructure to our fellow Wisconsinites. After all, we represent Wisconsin and have Wisconsin's best interests in mind.

Second, there will be in-depth discussion of costs. Speakers after me will likely discuss two different studies and multiple transmission projects in other states. The key point to remember is that the price a company initially bids to construct a project is not the same as the final cost to ratepayers.

WISCONSIN STATE CAPITOL
PHONE: (608) 266-5400 P.O. Box 7882, Madison, WI 53707 EMAIL: Sen.Bradley@legis.wi.gov

The opponents of this bill would love if that was the case, but in reality the price merchant developers bid often bears no actual resemblance to the final price ratepayers ultimately pay. For example, the Ten West Link project or Delaney to Colorado River received five bids with a winning bid of about $242 million and an estimated completion date of May 1, 2020. Today local consumers are still waiting for the project to be complete, but earlier this year DCR Transmission, the company who won the bid, asked FERC to approve a transmission tariff of $553 million, more than doubling the cost.

For better or worse, we are all aware that there are companies who submit bids they have no realistic way to meet only to raise prices later through a series of revisions. They say there are cost caps, but what they don't say is that there are exceptions to the cost caps. The key thing to remember is that the final cost to ratepayers is what matters, not the initial bid.

It is important to note that the Brattle Study that opponents of this bill will cite is focused on bids, not final costs and only examined sixteen projects in two regions. Instead of relying on final costs, they projected cost increases, and those theoretical savings of course never made it to the pocket of a ratepayer. In many cases like Ten West Link, initial bid amounts have no relationship to the final tariff cost passed on to ratepayers.

You will also hear about the economic advantage for ratepayers to have an incumbent transmission company build and own a project. Incumbent companies can defray a greater share of the actual cost paid by Wisconsin ratepayers on future regional projects in the MISO region. Without a Right-of-First-Refusal this advantage disappears for Wisconsin ratepayers.

This in combination with the significantly lower cost of ATC or Xcel operating and maintaining these lines long term makes Wisconsin's adoption of this bill a win for our ratepayers. As you hear the testimony related to cost I would encourage you to ask future speakers if they are describing bids at the beginning of the process or actual costs paid by ratepayers when a project is completed and in operation.

Ratepayers in my district prefer the kind of savings that actually make it to their bank accounts over theoretical savings and I would expect that is also the case in Superior, Arcadia and Viroqua as well.

Thank you for your time. I appreciate your consideration of this bill.

Testimony
Tony Clark, Sr. Advisor
Wilkinson Barker Knauer LLP
Wisconsin State Assembly - AB 470
Committee on Energy and Utilities
October 10, 2023

Chairman Steffen and Committee members, thank you for the opportunity to appear before you today. My name is Tony Clark. I am a Senior Advisor at the firm of Wilkinson Barker Knauer LLP, and I am testifying on behalf of our client ATC. I am here today to speak in favor of AB 470. By way of background, prior to my position, I was a Commissioner of the Federal Energy Regulatory Commission (FERC), before that, Chairman of the North Dakota Public Service Commission, and prior to that a state legislator in North Dakota. I'm also a native of Wisconsin. My family roots are in Rock County, but I was born in Platteville. And though I've lived most of my life in North Dakota, I am fortunate in that my family and I are able to spend a couple of months each summer at our lake cabin in Barron County. It's all a long way of saying that I have more than a passing interest in making sure Wisconsin gets energy policy right.

The issue before you today is relatively straight-forward. For a certain category of larger transmission lines, there are one of two ways to determine which entities will be responsible for developing the projects inside the borders of the state. As legislators, you have the ability to decide which of these two paths are taken.

One option is the traditional method of transmission development, in which needed projects are identified by MISO, the regional grid operator, and then assigned to Wisconsin's existing utilities for completion. Under this structure, projects and routes are developed, sited and built by the companies that are more comprehensively regulated by the state PSC, because they are the companies that serve customers within the state. When it comes time for cost recovery of the lines, they are placed into service at regulated rates to ensure the utility is charging a "just and reasonable rate."

The second option is a more recent invention that was created by FERC just over a decade ago. Under this newer regulation, the projects are still identified by MISO, but instead of being assigned, they are bid out through a process where non-traditional transmission companies, called "merchants," can also attempt the be selected to develop a project.

Unlike traditional customer serving utilities, these merchants may have little nexus with the state or those who use electricity here. They may be foreign private equity funds with opaque ownership structures and no familiarity with construction and operation of critical infrastructure in Wisconsin. When the project is bid by MISO, the companies seeking to win the transmission line do not have a route, a site certificate or even certain design parameters regarding pole construction and layout. MISO then selects one of the bidders based on a formula that includes cost and other parameters. But just as in first option I described, once the line is built, the developer seeks to place into regulated rates the full and true cost of the project.

Regardless of the method that selects the project, once built, the line is a monopoly. Customers don't get to choose their own transmission line. The question for the state is – which way of assigning responsibility for the line produces the best outcome for customers and landowners?

And when it comes to answering that question, there is little doubt that the traditional method for assigning lines is producing better outcomes. Let me be clear, if the second way of developing lines was working well for consumers and landowners, I would not be here today. The idea FERC had was that consumer outcomes would be improved through the new competitive solicitation process. But as Milton Friedman said, "One of the great mistakes is to judge policies and programs by their intentions rather than their results."

By all accounts, the nation's transmission grid is likely to expand in the coming decades. It's being driven by electrification, growing demand, and a power system that is incorporating more renewable generation. Getting this right is important, because customer dollars and landowner impacts are at stake.

The new FERC bidding policy was promulgated under a regulation called Order 1000. But however well-intended, what it has sowed is not healthy competition, but rather a dysfunctional process for building out the grid. Merchant developers, with little local knowledge of the land, and lacking on-the-ground resources where they propose to build the lines, are using the federal bidding process to win the right to build the project, but then repeatedly failing to deliver the projects as promised.

It is an unforeseen consequence of a federal rule which separates transmission development from the local communities that are being served. It can saddle customers with poorly executed, over budget projects. It is a costly race to the bottom in the development of some of our nation's most important critical infrastructure.

In the years since FERC created the new process, it has resulted in added expense, delay and controversy. Reports have detailed numerous problems. The last time I spoke before this Committee, I discussed the tortured tale of a project developed under the new bidding process. It was a 3-mile transmission project and associated substations which took seven years to compete, and even when finished, it incurred operational problems. In the process, it nearly caused the State of Delaware to upend its entire siting statute over concern for the consumer impacts of the project.

A more recent New York project which went through this process resulted in a 67 percent cost overrun that will likely be passed along to the state's consumers.

In Kansas, the regional grid operator selected a project that will result in landowners being forced to host multiple lines on their private property. As one Kansas regulator pointed out, had incumbent utilities been assigned the project, a single line could have been upgraded, thereby minimizing the impact on farmers, ranchers and the environment.

In New Mexico, the regional grid operator, for reasons that are not entirely discernable, selected a merchant developer to build a line even though the existing utility was willing to build it more quickly and for less money.

And perhaps the most startling recent example of the failure of the "bid" process is a merchant developer in California seeking to charge customers hundreds of millions of dollars in extra costs for a line that is 3 years overdue and costing more than twice what was bid. In this case, an international developer won the right to build the line at a bid of $242 million. The grid operator estimated it would cost approximately $300 million, so those who support the bidding process could claim that "competition" saved about $50 million. But now that the project is finally under construction, the developer is seeking to charge ratepayers $553 million. The California PUC estimates the line was only a reasonable and prudent investment for customers if it cost under $389 million. FERC Commissioner Mark Christie said plainly that anyone thinking that competitive solicitation is a "magic bullet" to lowering consumer costs had better "think again." In his words, the bid process, "does not cure or in any way prevent consumers from being hit with exorbitant and ever rising costs from transmission being built not to serve their need for reliable power, but to serve other interests."

What I believe is happening is one of two things, and neither is good. Either the bidding process is being gamed by developers, who know that the key is to win the bid, however you have to do it, because once you win the bid, there is little to discipline their actual costs. Or, the bidding bureaucracy itself is flawed, because the grid operators are asking developers to bid on projects without knowing key elements, such as where it will actually go, and what basic design elements of the line should be. In this case it is little wonder why merchant bids are sometimes significantly different from established operators – because incumbent utilities will generally have a better sense of what a project will cost to properly build in a given area.

Finally, you will hear developers tout that they build into their proposals cost caps or binding cost containment measures – but offramps and exceptions make these caps illusory. Or as Commissioner Christie said, the caps, "may subsequently be honored more in the breach than in the observance; in other words, the cost cap applies until it doesn't." Furthermore, when projects are not brought online in a timely manner, which has been the case with several merchant projects, it means customers lose the time value of a needed project. In short – the bidding process is shifting greater risk onto customers than would happen if projects were simply directly assigned to the properly regulated companies that serve customers in the state.

These are just a few examples, but they highlight that this federal rule is broken, and electricity customers and landowners are paying the price for it. If you would like to read more examples of the dysfunction of this federal rule, I would encourage you to read two reports authored by Concentric Energy Advisors, copies of which can be made available to the Committee.

Fortunately, FERC allowed states the option of continuing to use the more traditional method of transmission development, which preserves greater local oversight and decision-making about the state's energy future. But to exercise the choice, states must adopt a "right of first refusal" law (or ROFR), which ensures that the existing utilities that serve the state have the first responsibility for construction, coordination, cost control and operation of the lines that are so important to the welfare of citizens. That is the reason you have AB 470 before you today.

Passing AB 470 will put Wisconsin among the majority of states in the Midwest that now afford their ratepayers and landowners the additional protections provided by a state ROFR law. States across the country, on a bipartisan basis, have embraced these laws as a means of protecting their consumers and ensuring that when new transmission is needed, it is built in a coordinated, efficient way.

Wisconsin utilities have greater accountability to state regulators and understand how to build and operate transmission in a state where reliable operations during winter weather can be a matter of life and death. When questions need to be answered about line siting, construction, reliability and operations, it means state officials will be calling local utility operators who actually serve customers in the state to get answers.

Wisconsin should adopt a common-sense ROFR law. It's good for local communities, landowners, private property rights, reliability and customer costs. It will help ensure the coming transmission build is done in a way that puts Wisconsin's interests first.

October 10, 2023

Energizing Your Future

TO: Assembly Committee on Energy and Utilities

FROM: Mike Hofbauer, Executive Vice President & Chief Financial Officer

SUBJECT: Assembly Bill 470

Mr. Chairman and Members of the Committee:

I appreciate the opportunity to provide testimony in support of Assembly Bill 470.

The idea that a Right of First Refusal (ROFR) for incumbent utilities to build transmission projects in Wisconsin would lead to higher costs for Wisconsin customers is simply wrong. Wisconsin customers will pay less for a regional transmission project that is built by an incumbent utility than they would if that project was built by an out of state developer. Holding everything else constant, if an incumbent utility builds such a project, Wisconsin rates will decrease, while rates will go up if an outside developer builds it. This is due to the way that costs are allocated across the region for these projects.

When ATC owns one of these regional transmission projects, we send a bill to the regional transmission organization, MISO. This bill doesn't only include the capital cost of the project itself; it includes an allocation of ATC's existing operating costs.

I know many of you are business owners. The concept here is similar to how income tax deductions work for a home office. If you use a room in your home to run your business, you can deduct the cost of furniture, computers and other office equipment on your tax return. You can also deduct a portion of your electricity, heating, homeowners' insurance and mortgage interest.

It's the same principle for allocating costs for regional transmission projects. ATC allocates a portion of its existing operating costs to the region that we would otherwise bill to our Wisconsin customers.

W234 N2000 Ridgeview Pkwy. Ct., Waukesha, WI 53188
(262) 506-6700
(866) 899-3204
atcllc.com

MISO collects these bills from all the transmission owners in the region. Then they allocate the total cost for all regional projects to customers based on usage of the system. The amount that MISO bills to Wisconsin customers for an ATC project is less than the amount ATC bills to the region for that project.

Let me illustrate this concept with actual data for existing ATC projects. ATC currently has two regionally cost-shared projects that have been approved by the Wisconsin Public Service Commission and are in service or will soon be in service. The first is the Pleasant Prairie – Zion Energy Center 345kv line that was placed in service in 2013. The second is the LaCrosse – Madison 345kv / Dubuque Co. – Spring Green 345kv, more commonly known as Badger Coulee and Cardinal - Hickory Creek. The Badger Coulee portion of the project was placed into service in 2018 and ATC's portion of the Cardinal – Hickory Creek line is expected to go into service at the end of this year. ATC recently submitted our 2024 rate sheets for these projects to MISO. The total amount to be collected by MISO for these projects in 2024 is $66.8 million. The cost of these projects is allocated across the MISO region based on customers' usage of the system. Based on information from MISO, we expect 12.5% of the cost, or $8.3 million to be billed to ATC's customers. Included in the $66.8 million total that ATC submitted to MISO is $10.1 million of operating expenses that have been subtracted from the amounts that ATC will bill to its customers in 2024. Because ATC is reducing its billings by $10.1 million for these projects, and MISO is only billing ATC customers $8.3 million, ATC customers will receive a net benefit of $1.7 million in 2024.

The same would not be true for an outside developer. That's because an outside developer does not have existing costs in Wisconsin; therefore it would not be able to provide the same cost reduction benefit to Wisconsin customers.

This same allocation methodology applies to regionally cost-shared projects being constructed in other MISO states. Costs are being shifted from those states and billed to Wisconsin customers. If incumbent transmission owners in Wisconsin don't have the opportunity to shift costs to other states, Wisconsin customers will bear higher transmission costs.

I would also like to point out that this bill would not eliminate competition from the construction of transmission lines. ATC utilizes a competitive bidding process for construction contractors, as well as for the purchase of equipment and construction materials. The bill codifies this process under the oversight of the Public Service Commission.

There is another benefit to Wisconsin from ATC's ownership of transmission lines. Public power entities, including WPPI Energy and several other municipal and cooperative utilities, have a 12% ownership share of ATC. Over the past 10 years, ATC has distributed over $197 million dollars to our public power owners. These owners can use their distributions to improve their local utilities, lower their customers' rates, or continue to invest in ATC, helping us deliver safe, efficient, and reliable energy to the state.

Thank you for the opportunity to provide this information for your consideration.

Mike Hofbauer

Mr. Chairman and Members of the Committee:

My name is Bill Marsan, Executive Vice President and General Counsel at ATC. I am here with my colleague Mike Hofbauer to testify in support of Assembly Bill 470. I will be speaking about the safety, reliability and public policy reasons why AB 470 is important for Wisconsin, and Mike will speak to you about why passing AB 470 will save money for Wisconsin consumers.

AB 470 is necessary to maintain Wisconsin's right to control the expansion and operation of the electric grid. Without this legislation, Wisconsin will have no say over who gets to build out major projects on the grid, and the current outstanding safety and reliability performance of the system will be at risk. Furthermore, as my colleague will explain, failure to pass this legislation opens the door for higher electric bills for Wisconsin consumers.

Wisconsin's build out, regulation and management of the electric grid has been a tremendous success story for more than 20 years. In the mid to late 1990's, the reliability of Wisconsin's electricity supply was at great risk. Ownership of the grid was fragmented and rolling blackouts loomed unless corrective action was taken. Thankfully, the Wisconsin Legislature took corrective action. Specifically, in 1999, the Wisconsin legislature helped consolidate the grid and establish ATC as a stand-alone grid company to help improve the safety, reliability and strength of the state's transmission system. It worked.

ATC has built a system that now has 10,000 miles of lines and 600 substations. According to the metrics, ATC has improved overall reliability of the system by as much as 33%. In the last 10 years, ATC has completed 26 transmission projects that required Wisconsin Public Service Commission approval and, on average, those projects have cost 12% less than the budget ordered by the commission. ATC projects are subject to a competitive bidding process for labor and materials, and the commission, in an open and transparent process, monitors that process.

Given the success of the Wisconsin model for building, operating and maintaining the grid, you may ask why this legislation is necessary. The answer is that the Wisconsin model is under attack from a failed federal mandate and the investor/speculators who want to take advantage of it.

FERC Order 1000, which went to effect a dozen years ago, attempted to mandate a federal process for the build out of large transmission projects in the states. The theory was that a competitive process regarding ownership would result in cost savings for consumers and faster project development. The reality has been quite the opposite. Where implemented, Order 1000 has slowed the development process and has resulted in massive cost overruns for several projects.

The problem is that Order 1000 is still on the books. Until and unless FERC repeals Order 1000, there is only one way for states to maintain control of transmission development and take advantage of the cost benefits for consumers - pass legislation like AB 470.

As of today, eight states in the MISO grid region have passed so-called right of first refusal legislation, including our neighbors in Michigan, Iowa and Minnesota.

As I stated, my colleague Mike Hofbauer will describe the compelling financial reasons for passing AB 470. I will describe compelling policy and operational reasons for doing so.

From a policy perspective, Wisconsin should not forfeit the control over who owns critical infrastructure in this state. Moreover, Wisconsin policymakers have long-term experience with its state-based utilities that have been here for decades, unlike the out-of-state hedge funds and other entities who want to make money by getting into the transmission business in Wisconsin. By comparison, Wisconsin grid utilities employ Wisconsin citizens, and have a record of accomplishment and commitment to the communities we serve. We are proud to live and work in Wisconsin and serve our neighbors.

From an operations perspective, allowing new, unproven transmission providers on to the Wisconsin grid complicates operation of the system, exposes the system to new reliability and safety risks, and duplicates operational investments already made and paid for by Wisconsin consumers. Frankly, failure to pass AB 470 would be a step backwards from the model this state adopted in 1999 and which has proved so beneficial to Wisconsin consumers.

The opponents of AB 470 have one message: Competition in transmission development is a good unto itself. Their claim is contrary to the reality of our experience under Order 1000, and is patently false when it comes to what Wisconsin consumers will pay for the grid unless AB 470 becomes law.

Opponents have also raised the fact that ATC opposed ROFR legislation in Minnesota many years ago and are trying to have it both ways. Not true.

At the outset of Order 1000, many transmission companies tried to build transmission in other states. Once the failure of Order 1000 was apparent and MISO states began passing right of first refusal laws, our obligation to our customers was to acknowledge the realities of the market and change course. Successful companies change strategy when market conditions change. The facts of this market make it clear that the best way to get transmission built and serve states without right of first refusal laws are putting their consumers at risk for higher rates.

To conclude, the choice before you is simple: You can go backwards, risk the reliability and stability of our grid, and raise rates for Wisconsin customers, or you can pass AB 470 and maintain the model that has created more than 20 years of grid safety, reliability and value for Wisconsin consumers.

Thank you for your time. I am happy to answer questions.

Testimony in Support for Assembly Bill 470
Karl Hoesly, President, Xcel Energy Wisconsin & Michigan

Thank you, Chairman Steffen and committee members, for hearing this bill today and allowing me to testify. I am Karl Hoesly, President of Xcel Energy in Wisconsin and Michigan. I have submitted written testimony on behalf of Xcel Energy for the committee and today I will go through the testimony to highlight the importance of AB 470.

Xcel Energy is the number one builder of transmission miles in the U.S. which means we own and operate one the largest investor-owned transmission systems in Wisconsin and the United States, specifically Wisconsin is the 6th largest behind much larger states of CA and TX. In fact, in the past 10 years, no other company in the country has built more new transmission lines ensuring a safe and lower cost system for our customers. Today, our company owns and operates more than 20,000 transmission miles and nearly 1,200 transmission substations across Wisconsin and nine other states.

Just like any major infrastructure provider, such as broadband, roads and highways, the transmission grid needs to be upgraded and expanded to serve existing and new customers. We are fortunate to live in a state that continues to grow economically – something I see every day in my travels throughout our service area in western and northwestern Wisconsin. Whether that is the full St. Croix Business Park in Hudson, the amazing development in downtown Eau Claire and La Crosse, the growing dairy farms in Marathon and Chippewa County, or the numerous meetings my team has each week with companies – large and small – looking to relocate to Wisconsin because of its quality of our workforce, low cost of living and supportive business environment - the trend is always upwards. And through each economic story, there is a common thread – these businesses need ready access to safe, reliable and low-cost electricity.

In Wisconsin, Xcel Energy serves one of the largest, most rural service areas in the state covering 20,000 sq. miles - located in 500 communities within 26 counties stretching from Bayfield to Viroqua and Abbotsford to Hudson. In Wisconsin, we locally own, operate and maintain more than 2,600 miles of transmission lines – the second most in the state behind ATC.

On behalf of our customers and communities, we strongly support AB 470 as it ensures the rightful control of transmission construction to our state's own local energy companies and not out-of-state interests who would use the federal bureaucracy and slow construction and add a year or more to each project. The surest way to ensure Wisconsin continues to grow our economy and meet the needs of our residents and businesses is to pass AB 470. Other states that have passed Right of First Refusal ("ROFR") laws, including 8 of 15 MISO states, emphasize a state's rights rather than a federal model to expand their transmission system. And all have successfully developed projects that access new generation resources, save customers money and increase reliability.

Federal regulation of transmission development does not work.
Others will attempt to cherry pick a few projects to support their premise against this legislation. However, it's a fact that they will not mention that the majority of the projects built under the federal bureaucratic process of competition were plagued by scope changes resulting in massive cost overruns and extreme delays. They also will act as if the federal process guarantees cost savings

through the bidding process, which it simply does not. Actual costs for these projects have almost always exceeded the low bids that are incentivized with the competitive bidding process.

A perfect example is the SPP Crossroads-Hobbs-Roadrunner project in southeast New Mexico where Xcel Energy serves.

- In this project, Xcel Energy, the incumbent was not selected, while an out-of-state contractor (NextEra) was the selected developer.
- The out-of-state developer's proposal was >30% higher and a year later commercial operation date and is siting the project where it wants using condemnation rather than working with property owners to site the project.

It is a fact that since FERC Order 1000 was passed over a decade ago it has been entirely unsuccessful in bringing more efficient projects to life. It has also resulted in far less collaboration, created extensive delays in development, imposed costly processes and removed control from local and state officials who know best what their communities need.

Let me give you a few examples:

- In several regions, such as California, local utilities have stopped altogether in participating in federal bureaucratic competitive processes.
- In the Southwestern part of the U.S., generally only four companies bid into projects.
- In the Midwest Independent System Operation region, the number of companies participating dropped by half between the first and second competitive projects that were provided.

In addition to these examples, there's tremendous risk to overall reliability when incumbent utilities don't construct these projects. Unlike in-state companies, out-of-state companies only need to maintain infrastructure for the first number of years when they are receiving revenue. But after the period when revenues decrease, they have little incentive to maintain that infrastructure. Conversely, local, in-state utilities are held accountable and are required by the PSCW to continue maintaining infrastructure for reliability and the safety and security of our residents.

Regarding price, I would like to note that we are fully regulated and mandated to file rate cases with the Public Service Commission of Wisconsin at least every other year. As you know, in these proceedings the Commission regulates the reasonableness of our rates, and it is in our best interest to have affordable rates to attract new business to our region and to have satisfied customers.

It is also worth underscoring that all new transmission projects built by Wisconsin utilities are subject to Wisconsin's robust Certificate of Public Convenience and Necessity process, which is reviewed by the Public Service Commission. This process includes ensuring the project is in the public interest and is competitively priced and bid.

In fact, a Concentric Energy Advisors study revealed that transmission projects awarded to out-of-state developers experienced an average of one year in schedule delay and a cost increase of 27%.

At Xcel Energy, we have a rich history of working together with other transmission owners to support development of the regional grid that enables economic growth in Wisconsin. In 2017,-the $2 billion CapX2020 transmission grid initiative involving Xcel Energy, Dairyland Power, ATC and many other utilities in the Upper Midwest was completed. Throughout that project, close to 800 miles of new transmission lines were energized in Wisconsin and three other states which changed the energy landscape in the region for decades to come. The success of CapX2020 has shown that state-led processes, not a burdensome, expensive federal process, leads to greater local control and engagement, and more streamlined planning, permitting, and construction.

In fact, CapX2020 has been described as a unique and innovative structure in which each of the 11 local partner utilities had equal representation, oversight and decision-making. A study published by the University of Minnesota's Humphrey School of Public Affairs said the key characteristics led to the success of the CapX2020 included setting common goals, creating a win-win situation, building relationships, following group governance, and providing transparency and open communication.

We have followed this same model since then and continued to build out the transmission system in northwestern Wisconsin. Here are a few examples:

Bayfield Loop

Over the past 10 years, we have completed projects including on a very challenging project on Bayfield Peninsula around the northern tip of Wisconsin along Lake Superior. For that project, an existing transmission line that was built in the 1950s, 60s and 70s was no longer adequate, experienced low voltages during peak days and provided no redundancy in the case of a large outage. In addition to upgrading the line and providing a second source of power, this project strengthens the overall system in the area. The entire project was done with local control and state oversight to ensure that it was on-time, on-budget and met the needs of our local communities.

Ashland-Michigan's Upper Peninsula

Also in northern Wisconsin, we are upgrading an important transmission line that runs from Ashland and connects to Michigan's Upper Peninsula. That transmission line was also built in the 1950s and 1970s and is critical to provide service to customers of Xcel Energy and the local rural electric cooperatives in the region including Bayfield Electric and Price Electric. At least 90 percent of this line runs through difficult terrains including wetlands, beaver ponds, bogs and rivers. In addition, a section also crosses the Bad River Native American reservation – also in a remote location that poses accessibility and environmental challenges. As part of this project, we will be removing the line from the reservation and as a local utility, we have worked closely with Bad River to maintain a strong working relationship on all issues associated with the project. This is a major project, and we expect it to be in service between 2026 and 2028.

Western Wisconsin

And in western Wisconsin, we have upgraded the majority of the transmission structures that connect from the St. Croix River to Eau Claire and on to Marathon County. This 345,000-kilovolt line is a critical reliability source for the entire state of Wisconsin and through these proactive efforts we upgraded structures that were 40-50 years old, to ensure that it provides the safe and reliable service our state has come to expect.

As these three examples show, it is impossible to imagine a scenario where critical transmission lines get built more efficiently than by ensuring our local transmission companies and officials have the first say in how they are developed. A strong and locally constructed and maintained transmission system will ensure continued reliable and affordable service; meet state and regional energy policy goals; and support a diverse generation mix for years to come.

WISCONSIN INDUSTRIAL ENERGY GROUP

44 EAST MIFFLIN STREET | SUITE 404 | MADISON, WI 53703 | PH: 608 441 5740 | WIEG.ORG

To: Assembly Committee on Energy and Utilities

From: Todd Stuart, Executive Director
Wisconsin Industrial Energy Group, Inc.

Re: Opposition to Assembly Bill 470

Date: October 10, 2023

Chairman Steffen and members of the Assembly Committee on Energy and Utilities, thank you for the opportunity to provide comments on Assembly Bill 470. Wisconsin Industrial Energy Group, Inc. respectfully offers these comments on behalf of its members in opposition to AB 470 regarding an incumbent transmission facility owner's right to construct, own, and maintain certain transmission facilities.

WIEG is a non-profit association of 25 of Wisconsin's largest energy consumers. The group has long advocated for policies that support affordable and reliable energy. Since the early 1970s, WIEG has been the premier voice of Wisconsin ratepayers and an engine for business retention and expansion. Each year its members collectively spend more than $400 million on electricity in Wisconsin. Most of these companies have electric bills of over $1 million each month, and it is one of their top costs of doing business.

WIEG and our members join ratepayer organizations like Citizens Utility Board, taxpayer advocate groups like Americans for Prosperity and Americans for Tax Reform, free market advocates like Wisconsin Institute of Law and Liberty, and other trade associations representing thousands of Wisconsin employees like Associated Builders and Contractors, Midwest Food Products Association and Wisconsin Cast Metals Association in opposing this legislation.

This bill eliminates competition on the development of large new regionally cost shared transmission projects approved by the Midcontinent Independent System Operator (MISO). Eliminating competition will almost certainly cost Wisconsin businesses and consumers more money. Without competition, there are fewer checks and balances on cost estimates, and little or no incentive to curb transmission project costs and prevent cost overruns.

Wisconsin's ratepayers simply can't afford additional cost burdens. High electric rates are effectively a tax on ***all*** Wisconsin homeowners and businesses. Wisconsin's electric rates have been well above the Midwest average since 2003 and continue to be above the national average. Energy inflation is a real issue in Wisconsin.

This is a major concern for our members, employing thousands of Wisconsin taxpayers across the state. With MISO expected to approve up to $100 billion of transmission projects for the Long Range Transmission Planning process (LRTP). Wisconsin has historically had a roughly 14% cost share of regional projects. If a similar percentage of cost sharing is applied to the new MISO projects, then Wisconsin would see billions of dollars in new costs from regional projects.

Transmission costs have been a contributing factor in Wisconsin's persistently high rates. Transmission has steadily grown and now makes up a significant and growing line item on electricity bills in Wisconsin. According to FERC filings, transmission costs increased at an annual rate of around 5% between 2005 and 2023. ATC's most recent 10-year year assessment is between $5.1 billion and $6.2 billion. This is probably ATC's largest capital expenditure plan ever and it is $1 billion more than the year before. The increase was almost entirely driven by including MISO's Tranche 1 of the "Future 1" scenario of its LRTP. Based on MISO's expansion plans, we have no reason to believe there will be any diminished rate pressure from the growth in capital expenditures related to transmission.

The Public Service Commission (PSC) has supported transmission competition at MISO because competitive bidding serves the public interest and promotes compliance with FERC Order 1000. Multiple regulatory and consumer agencies, including National Association of Regulatory Utility Commissioners (NARUC) and National Association of State Utility Advocates (NASUCA) filed comments in recent years related to FERC Order 1000 in support of competition.

President Trump's Department of Justice said that bills like AB 470 will increase costs, reduce reliability and harm consumers. The Trump administration commented on the Texas version of AB 470: *"such laws can similarly reduce competition and thereby harm consumers... consumers may face higher electricity rates and less reliable service as H.B. 3995 [the Texas version of AB 470] may limit construction of transmission that would increase the supply of generation available to serve a local territory or area."*

According to studies by the Brattle Group, competition to build regional transmission projects drives cost savings between 20% - 30%, and when cost overruns by incumbent utilities are factored in, the cost savings are estimated closer to 50%.

Real world examples demonstrate how competition can spur innovation and create savings for customers. Within the MISO footprint, there have been projects that show the benefits of competition. The Duff-Coleman Project in Indiana and Kentucky was the first FERC Order 1000 competitive solicitation. There were 11 proposals for the approximately $60 million project, including multiple MISO transmission owners and transmission owners from other regions competing outside their service territory. Duke Energy and ATC (DATC) and Xcel Energy bid on the project. The winning bid had financial concessions consisting of cost caps, a reduced return on equity and a guaranteed schedule. It also had a strong use of local partners in its operating and maintenance plan.

More recently, MISO announced the results of a competitively bid new line in May 2023. The Hiple to Indiana/Michigan State Border project is a 30-mile 345 kV transmission line. It was for the first project of the Renewable Integration Projects that are part of Tranche 1 LRTP. There are cost caps in place. The financing is set at 9.8% rather than ATC's return on equity of 10.52%. As a result of the competitive process, the Hiple to Indiana/Michigan State Border project will cost about 26% per mile less and save $177 million versus MISO's original estimate.

The schedule guarantees and reduced return on equity are significant long-term benefit to the consumer. These commitments end up being incorporated into binding and enforceable contracts with MISO. In other words, if there are delays or cost overruns, the developer must absorb the financial consequences. If AB 470 would be signed into law, then the protections are removed and large, regionally cost shared projects default to the incumbent utilities. The excess costs to consumers resulting from the lack of competition would be easily reach into the billions from overruns and/or lack of financial concessions.

Outside of the MISO footprint, competition has secured significant savings around the country. In recent years:

The Maine Public Utilities Commission has estimated savings of over $1 billion for consumers from two new electricity transmission projects from competitive bidding.

New Jersey had the largest-ever competitive bidding process for a transmission project in the country - saving an estimated $900 million.

New York's Empire State Transmission Line was selected by the New York Independent System Operator (NYISO) through a competitive bidding process. The first competitively bid transmission project awarded and built in New York had an estimated savings of $500 million.

The Crossroads – Hobbs – Roadrunner 345-kV Competitive Upgrade Project is the fifth and largest competitive transmission project that the Southwest Power Pool (SPP) has released and will deliver an estimated $84 million in savings to New Mexico.

The Wolf Creek to Blackberry transmission project, a 94-mile 345 kV line, was competitively bid and the least expensive proposal was selected. The line between Kansas and Missouri saved an estimated $58 million.

The Minco-Pleasant Valley Draper transmission project, a 48-mile, 345 KV line, was competitively bid with regulators selecting the least costly proposal. This line in Oklahoma saved an estimated $26 million.

We note that ATC or DATC, Xcel and ITC have never won a competitive project inside the MISO footprint or elsewhere in the United States.

Wisconsin has one of the most manufacturing-dependent economies in the country. Our member companies support 35,000 good paying jobs, compete locally, regionally and globally. Energy costs are one of the primary factors considered for retention, relocation or expansion for manufacturers throughout our great state.

Many utility customers, both large and small, had double-digit rate hikes on their electric bills starting January 1, 2023. On top of that, many customers are about to have fuel surcharges added to their bills for the remaining months of 2023. The PSC is currently reviewing roughly a half billion dollars in higher electric and natural gas rates for 2024 and 2025.

Wisconsin's energy inflation and uncompetitive electric rates are a threat to our industries. Removing competition will cost Wisconsin businesses and taxpayers more money, ~~and that is why members of this committee should vote no on this bill.~~

milwaukee
journal sentinel
PART OF THE USA TODAY NETWORK

Power line owner ATC flips position, backs legislation on rights to transmission expansion

By Patrick Marley of the Milwaukee Journal Sentinel
February 7, 2022

MADISON – An energy transmission company is urging Wisconsin lawmakers to pass legislation that would guarantee it would be the one to build future power lines — flip-flopping from the position it took on an identical Minnesota law.

The measures in the two states are meant to ensure the owners of power lines can build additional ones, but the effects of them for American Transmission Co. are not the same.

The Minnesota law keeps ATC from building lines because it has few existing lines there. The Wisconsin legislation would give it a lock on building more lines in much of the Badger State.

The Wisconsin bill has backing from Republicans and Democrats who sit on legislative committees that oversee utilities. It has attracted an unusual collection of opponents that includes environmentalists and Americans for Prosperity, the conservative heavyweight that was formed by industrialists Charles and David Koch.

Senate Bill 838 would allow the owners of transmission lines to build lines that connect to their existing ones, preventing competitors from trying to get the work.

That would benefit Pewaukee-based ATC, which owns more than 10,000 miles of transmission lines in the Midwest, primarily in Wisconsin and Michigan's Upper Peninsula. WEC Energy Group and other utilities have an ownership stake in ATC.

When the similar measure came up in Minnesota, ATC fought it.

The Minnesota bill "would stifle competition in the development and construction of electric transmission facilities leading to higher costs for electricity users in Minnesota," ATC lobbyist John Garvin wrote in a memo he sent to Minnesota lawmakers in 2012.

Now the company is taking the opposite view in its home state, where it stands to gain financially.

ATC officials were interested in developing projects in other states when Minnesota considered its law, according to Bill Marsan, ATC's executive vice president and general counsel. Over the following years, their view changed as they had a chance to better understand new federal rules for transmission lines, he said in a written statement.

"What we learned over time, and based on experience, was that the federal process failed to deliver competitive projects. ATC changed its position based on the reality of the market and our conviction that the best way to actually get transmission built and serving customers was through the traditional state regulatory process," he said in his statement.

Eric Bott, director of Americans for Prosperity-Wisconsin, said ATC is trying to get states to adopt policies that are best for it depending on the circumstance — even when those policies contradict each other from one state to the next.

"They want to have it both ways," he said in an interview. "They want government in Wisconsin to protect them from competition, right? But they want to be able to compete for work in other states."

'Really, this is cronyism'

Bott argued letting other companies bid on new power lines would keep prices down for electric ratepayers. It would also help keep jobs on time and prevent budget overruns, he contended.

"Really, this is cronyism," he said. "If you read the bill on its face, the purpose is to fence out competition and protect the home team."

Supporters say the legislation is necessary because without it decisions on transmission lines will be made by Midcontinent Independent System Operator Inc., a nonprofit organization overseen by the Federal Energy Regulatory Commission.

"What this bill does is protect Wisconsin's ability to have a say in who owns and maintains critical infrastructure in our state," Ellen Nowak, a member of the utility-regulating Public Service Commission, said in recent testimony to the Assembly Utilities Committee.

"Forfeiting Wisconsin's ability to determine who can build here and replacing our process with a slow, cumbersome bureaucratic process run by the federal government or an arm of the federal government is not in the best interest of Wisconsin."

Nowak has served as a commissioner for most of the last decade, though she took a break from the job in 2018 to serve as administration secretary in Republican Gov. Scott Walker's last year in office.

It's unclear whether backers can get the bill through the Republican-controlled Legislature before the session ends in March — and whether Democratic Gov. Tony Evers would sign it if they do.

In rolling out the legislation in December, Republican Sens. Julian Bradley of Franklin and Roger Roth of Appleton said the legislation was needed for "ensuring that Wisconsin will control the expansion and operation of the grid that meets the needs of customers."

Bradley is the chairman of the Senate Utilities Committee and Roth is the vice chairman. Also signing onto the legislation are the committee's other members — Republican Sen. Van Wanggaard of Racine, Democratic Sen. Jeff Smith of Brunswick and Democratic Sen. Brad Pfaff of Onalaska. Pfaff is running for Congress.

The bill has the support of the Metropolitan Milwaukee Association of Commerce, the Construction Business Group and utilities, including Xcel Energy and Dairyland Power Cooperative, which like ATC own transmission lines in Wisconsin.

The bill's opponents include the Wisconsin Institute for Law & Liberty, a conservative group focused on free-market issues; Clean Wisconsin, an environmental group; the Wisconsin Industrial Energy Group, which represents businesses that use large amounts of power; and the Citizens Utility Board of Wisconsin, which seeks to keep prices down for ratepayers.

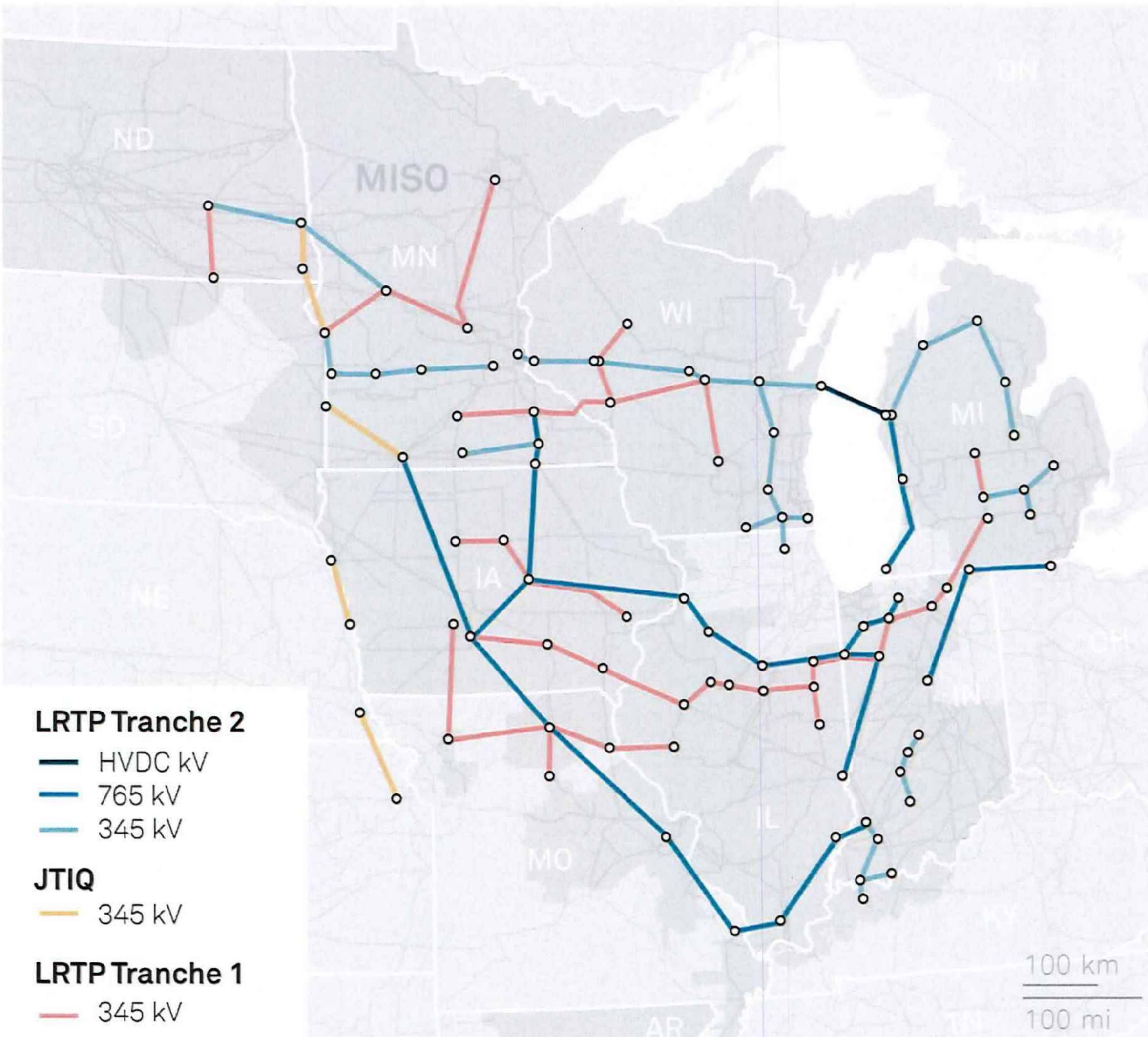
Opponents of the bill have tried to sway Republican lawmakers by noting the U.S. Department of Justice under former President Donald Trump raised objections to similar legislation in Texas in 2019.

Daniel Haar, an acting section chief of the Department of Justice's antitrust division, submitted testimony to a Texas legislative committee saying the proposal there could drive up prices.

"The Division is concerned that these restrictions would limit competition, thereby potentially raising prices and lowering the quality of service for electricity consumers," Haar wrote.

Potential LRTP Tranche 2 projects

MISO has identified an initial set of hypothetical projects to meet its updated Future 2 scenario for fleet change and demand growth.



Source: S&P Global Commodity Insights, MISO

- $20 Billion to $30 Billion for Tranche 2
- MISO Board System Planning Committee Review, December 2023
- MISO Board Approval, Before End of June 2024

To: Members of the Assembly Committee on Energy and Utilities

From: Megan Novak, State Director, Americans for Prosperity - Wisconsin

Date: October 10, 2023

Subject: Support Ratepayers, Oppose AB 470

Chairman Steffen, and members of the Assembly Committee on energy and Utilities, thank you for the opportunity to provide testimony opposing Assembly Bill 470.

Americans for Prosperity – Wisconsin believes freedom and opportunity are the keys to unleashing prosperity for all. Through our community of activists in every corner of the state, we advocate for solutions, based on proven principles, in order to tackle the country's most critical challenges.

One of the growing challenges for Americans right now are high energy costs. Too many families and business owners are facing seemingly non-stop hikes in their monthly energy bills, which can limit their ability to live out their version of the American Dream. Unfortunately, the bill before this committee today, would risk yet another rate hike for Wisconsinites. With our state already having some of the highest electricity rates in the Midwest, another increase would be devastating to families and businesses already struggling under the inflationary economy of Bidenomics.

Assembly Bill 470 would eliminate competition for building new large, regional transmission lines in Wisconsin, by only allowing current, incumbent companies to build these projects. Said in other terms, Assembly Bill 470 increases costs for Wisconsin families and businesses, by eliminating the benefits of free market competition such as consumer-friendly financing packages that can include cost caps on overruns and delivering projects on time.

Competition is critical in all sectors of our economy, regardless of how regulated that sector is. The Legislature in recent years has correctly used public policy to support competition to drive better outcomes for consumers. For example, in K-12 education we continue to support and work to expand education options to give families a choice and in hopes that it drives all schools to improve outcomes for students. Health care is another highly regulated industry, but there are continued efforts to push competitive forces to improve access to high quality and affordable care. The energy and utility space should be no different than these examples.

In Wisconsin, a transmission owning utility can earn up to a 10.52% profit on any new line they build through their authorized 'return on equity'. Eliminating competition in these massive projects also eliminates any incentive to keep project costs down or for the company to even consider lowering this return on equity.

We have seen from other projects that have been let to bid that competition does in fact save millions of dollars in the long run:

- $1 billion estimated savings[i] from two new electricity transmission projects in Maine.
- $900 million estimated savings[ii] on the largest-ever competitive bidding process for a transmission project in the country in New Jersey.
- $500 million estimated savings[iii] on the Empire State Transmission Line in New York.
- $58 million estimated savings[iv] on the Wolf Creek to Blackberry transmission project in Kansas and Missouri.
- $26 million estimated savings[v] on the Minco-Pleasant Valley Draper project in Oklahoma.
- $84 million estimated savings[vi] on the Crossroads- - Hobbs – Roadrunner upgrade project in New Mexico.

For another example of the importance of competitive bidding, attached to this testimony is the MISO selection report for the Hiple to IN/MI State Border 345 kV transmission project. Developer C was the winning bid for this project. As you can see, their bid included a lower 9.8% initial return on equity, with additional ROE reductions for any project delays, along with annual revenue caps. The winning bid came in at over $1.2 million lower per mile than the highest bid – a 26% savings for ratepayers.

From economic analysis and studies to these real-life examples, competition on transmission projects can and does reduce costs to consumers by up to 33% or more. These real-life examples show the significant savings that will be realized by ratepayers in other states – shouldn't Wisconsinites expect to benefit from similar savings as well with billions of dollars of new transmission line projects coming to our state over the next few years?

Proponents of this legislation have stated two main reasons why incumbents should not have to compete for future projects: built in savings from being an incumbent and reliability. To the first, we say prove it. If there truly are built in savings from already operating in Wisconsin, any competitive bid an incumbent company submits for a project should reflect these savings and likely give them a leg up in the bidding process. On the point of reliability, the companies that are eligible to bid on MISO transmission line projects must go through a robust application process that includes strict and rigorous requirements on reliability. Attached to this testimony are the nearly 50 companies, including Wisconsin's incumbents, that MISO has reviewed and approved for competitive bidding, based in part, on their reliability.

In Wisconsin, families and businesses are already struggling with rising energy costs. Governor Evers' appointees to the Public Service Commission have approved double digit rate hikes over the last few years and are currently considering another round of substantial rate hikes for many customers.

AFP-Wisconsin hears almost daily from our activists and from voters we talk to on the phone and the door about their absolute shock in how much utility bills have already been increasing. These voters come from every corner of the state and every walk of life, but almost every single person our organization talks to is shocked and upset by their monthly bill.

Over time, Assembly Bill 470 would only serve to make these problems worse: rate hikes on those who can least afford it and rate hikes that will make our manufacturing and business sectors less competitive nationally and internationally. Simply put, Wisconsinites cannot afford this policy.

Chairman Steffen and committee members, we strongly urge you to reject Assembly Bill 470 and instead support competition and lower energy costs for all Wisconsinites.

---

[i] Maine Public Utilities Commission, *Commission Selects Winning Bids for Northern Main Transmission Line and Renewable Energy Projects*, (10/26/2022) available at https://www.maine.gov/tools/whatsnew/index.php?topic=puc-pressreleases&id=9382450&v=article088; *see also* Electricity Transmission Competition Coalition, *Competitive Electricity Transmission Bidding Process Saves Main Consumers over $1 Billion*, (10/26/2022) available at https://electricitytransmissioncompetitioncoalition.org/competitive-electricity-transmission-bidding-process-saves-maine-consumers-over-1-billion/

[ii] New Jersey Board of Public Utilities, *New Jersey Board of Public Utilities Selects Offshore Win Transmission Project Proposed by Mid-Atlantic Offshore Development and Jersey Century Power & Light Company in First in Nation State Agreement Approach Solution*, (10/26/2022) available at https://nj.gov/bpu/newsroom/2022/approved/20221026.html; *Also see* Electricity Transmission Competition Coalition, *Competitive Electricity Bidding Process Saves New Jersey Ratepayers Billions of Dollars,* (11/1/2022) available at https://electricitytransmissioncompetitioncoalition.org/competitive-electricity-transmission-bidding-process-saves-new-jersey-ratepayers-billions-of-dollars/

[iii] NextEra Transmission, *New York Gov. Hochul joins NextEra Energy Transmission to celebrate commissioning of Empire State Transmission Line*, (07/11/2022) available at https://www.streetinsider.com/PRNewswire/New+York+Gov.+Hochul+joins+NextEra+Energy+Transmission+to+celebrate+commissioning+of+Empire+State+Transmission+Line/20311212.html; *also see* Electricity Transmission Competition Coalition, *Statement from ETCC Chair Paul Cicio on NYISO's New, Competitively Bid Empire State Line Project*, (07/12/2022) available at https://electricitytransmissioncompetitioncoalition.org/statement-from-etcc-chair-paul-cicio-on-nyisos-new-competitively-bid-empire-state-line-project/

[iv] Electricity Transmission Competition Coalition, "Competition Works" available at https://electricitytransmissioncompetitioncoalition.org/competition-works/

[v] Southwest Power Pool, *Minco-Pleasant Valley-Draper RFP* available at https://www.spp.org/documents/66929/minco-pleasant%20valley-draper%20rfp%20iep%20public%20report.pdf

[vi] Electricity Transmission Competition Coalition, *Competitive Electricity Transmission Bidding Process Saves New Mexico Consumers $84 million* available at https://electricitytransmissioncompetitioncoalition.org/competitive-electricity-transmission-bidding-process-saves-new-mexico-consumers-84-million/

AARP Wisconsin

222 W Washington Ave. | Madison, WI 53703
O: 866-448-3611 | F: 608-251-7612
aarp.org/wi | wistate@aarp.org | twitter: @aarpwi
facebook.com/aarpwi

ASSEMBLY ENERGY AND UTILITIES COMMITTEE
ASSEMBLY BILL 470
TESTIMONY OF AARP WISCONSIN

October 10th, 2023

Good afternoon, Chairman Steffen and committee members. On behalf of AARP Wisconsin's 800,000+ members and our State Director Martha Cranley, I want to share thoughts on AB470.

We are interested in this legislation because it could lead to raising electricity rates for our members and Wisconsin electricity consumers in general. AB 470 is an inappropriate end run around sound Federal policy which requires competitive bidding of large new scale transmission projects. MISO (the grid operator serving Wisconsin) and Wisconsin's transmission developer, ATC (owned by We Energies), have proposed a concerning amount of new long-distance transmission without increased state population growth to demand it. Such costly transmission spending is an increasing driver of Wisconsin's frequent electricity rate increases while it pads the profits of the top market-controlling (monopoly) utilities by increasing their rate base.

Right now, the Midcontinent Independent System Operator (MISO) and its voluntary utility members are pushing a second series of transmission projects for $9 billion after just securing a first tranche last year, making it $18 billion in total. Fifteen percent of this amount will end up in Wisconsin's electricity rates and much of it is to benefit other states. ATC is proposing no less than six large new transmission line projects in the state. MISO's own independent market monitor has stated that some of this transmission is not needed as local alternatives like local solar and local generation are more cost-effective. He says MISO's assumptions are incorrect.

In any event, this harmful and unnecessary bill would void current Federal policy and give exclusive rights to ATC to construct large new transmission lines in the state. In addition, the fact that other top market-controlling (monopoly) utilities in Minnesota, North Dakota, and a few other states have secured passage of a similar bill in their state is testimony only to their political muscle, not to the merits of the bill. Further, having ATC competitively bid engineering and other duties (instead of MISO) is a misguided idea since ATC is not independent and has no incentive to keep costs down. More importantly, estimates show that such projects could cost at least 20% less with competitive bidding as is required today, without this legislation.

AARP and other groups have opposed similar proposals last session in Kansas, Missouri, Illinois, and other states because they are detrimental to consumers. It has been rejected by the court in both Texas and Iowa.

We urge you to vote no and reject this unnecessary legislation with unintended consequences. Wisconsin's residential electricity customers, who already pay the second-highest electricity rates in the Midwest, cannot afford it especially given all the utilities are now before the PSC for yet another series of rate increases.

David Bowen
Assoc. State Director of Advocacy

CUB CITIZENS UTILITY BOARD

Citizens Utility Board of Wisconsin, Inc.
Thomas Content - Executive Director

P.O. BOX 8983 | Madison, WI 53708-8983
608-251-3322 | staff@cubwi.org

To: Members of the Assembly Committee on Energy and Utilities
From: Tom Content, Executive Director, Citizens Utility Board of Wisconsin
Date: October 9, 2023
Re: Opposition to Assembly Bill 470

Chairman Steffen, Vice Chair Summerfield and members of the committee, thank you for the opportunity to provide input on Assembly Bill 470 today. I'm Tom Content, Executive Director of the Citizens Utility Board of Wisconsin, or CUB. CUB respectfully requests that you keep cost saving tools in the regulatory toolbox for customers we represent across Wisconsin and oppose this incumbent monopoly utility protection legislation.

CUB advocates on behalf of homeowners, renters and small businesses across the state — the residential and small business customers of Wisconsin's electric, natural gas and water utilities. CUB is a nonpartisan non-profit organization created by the Legislature in 1979 to level the playing field in cases at the state Public Service Commission and provide representation for small customers. CUB advocates for safe, reliable and affordable utility service.

This bill undercuts affordability efforts by blocking an opportunity to find cost savings or project improvements when major power lines are built. Consumer advocates and customer groups across the country have mobilized in the name of cost savings to support competitive bidding for projects as part of an expected multi-billion-dollar expansion of the Midwest and national power grid.

Transmission spending is taking up a larger share of a typical customer's electric bill, and Wisconsin customers today pay the second highest electricity rates in the Midwest. Our electricity rates rank among the top 15 most expensive states in the country for residential and business customers, and a Midwest comparison this year found residential and business rates for most Wisconsin investor-owned utilities rank in the top quartile in a comparison with IOUs across 12 Midwest states.

Competitive bidding has been shown to save up to one-third or more on transmission line costs. Significantly, cost caps in competitively bid projects assure that utility customers aren't on the hook for cost overruns. Those savings are being seen around the country, and the in our region Midwest Independent System Operator has now selected several competitively bid projects.

For CUB members and utility customers across the state, the cost pressures keep coming. This is why CUB is highlighting affordability as a goal that regulators and policymakers here in the Capitol need to keep top in mind.

Many customers experienced double-digit increases on bills earlier this year, and more of the same is being proposed right now for other customers. This fall customers across the state are submitting comments or speaking at public hearings on currently pending proposals to raise prices by $500 million or more. That includes hearings taking place just yesterday in Milwaukee.

Current Wisconsin law does not require competitive bidding. Rather, it holds it out as an option for when competition is appropriate. If concerns exist over the level of control non-Wisconsin entities such as the Midcontinent Independent System Operator have over the selection and design of transmission projects to be built in our state, this bill is not the solution. Rather than increasing the amount of control our state has over transmission projects to be built within our borders, it would hand even more control to MISO as it would streamline the process between when MISO identifies the need for a project and when that project comes before our Public Service Commission.

It would throw away the opportunity for competitive bidding, opportunities that are already severely limited due to MISO's rules. It would throw away the tool this legislature has long preserved to make sure all options are on the table to help ensure that only the best and most cost-effective projects are paid for with utility customers' money. In short, rather than improving state control over transmission investment, this bill would have Wisconsin hand over the keys, not only to MISO but also to any potential future federal push to increase transmission investment to enable more renewable energy and decarbonize our electricity sector.

Now I'd like to highlight some recent developments on this issue around the country and in the Midwest.

CUB serves on the Executive Committee of the National Association of State Utility Consumer Advocates, a voluntary association of 60 consumer advocate offices in 44 states and the District of Columbia. Most of these offices are within a state Attorney General's office or an independent state agency.

In a diverse national group representing states on the coasts and here in the heartland, it's often hard to find consensus. But on this issue, we did. NASUCA consumer advocates agree on the value of competitive bidding for major transmission projects, and are highlighting that – in developments since the last version of this bill was in front of this committee.

In June 2022, NASUCA passed a transmission policy resolution that states in part:

> "Competitive bidding for transmission services should result in greater innovation and lower prices for consumers. In addition, competitive bidding should improve operating efficiencies and will shift business risk from monopoly customers to competitive transmission providers."[1]

A copy of the resolution is attached to my testimony.

---

[1] NASUCA Resolution 2022-01, Urging the Delevlompent of Consumer Protection Policies for Interconnection and Electric Transmission and Distrribution Planning and Development, June 2022

Also last year,[2] and again this year,[3] NASUCA submitted comments to the Federal Energy Regulatory Commission underscoring the value of competitive bidding and opposition to plans to undercut that through ROFR. NASUCA highlighted consumer protection issues in FERC's Building the Future Transmission rulemaking. Among these: "Competition should be the primary method for determining who builds transmission projects."

The comments went on to say:

> "NASUCA believes that allowing entities to compete on price to win the opportunity to build defined projects will result in the lowest cost for consumers. In a process arguably controlled by incumbent transmission owners, eliminating the opportunity to bring competitive suppliers and competitive pressures into play for the benefit of consumers is the wrong policy direction."[4]

This year we have seen developments in nearby states. The Iowa State Supreme Court overturned a ROFR law that was enacted despite customers' opposition in a state where transmission costs have surged and become a significant share of customers' rising bills.

More recently, just two months ago, Gov. J.B. Pritzker vetoed a ROFR bill in Illinois, saying Illinois utility customers were facing higher costs under the legislation. "Without competition, Ameren ratepayers will pay for these transmission costs at a much higher costs, putting corporate profits over consumers," he said.[5]

CUB stands with our consumer advocate colleagues in nearby states and across the country in support of effective policies that support affordable utility bills. That includes retaining competitive bidding on major power line projects. CUB respectfully requests your assistance in keeping utility costs in check by voting against AB 470.

Thank you.

Attachment: NASUCA Resolution 2022-01 – *Urging Development of Consumer Protection Policies for Interconnection and Electric Transmission Planning and Development*

---

[2] Initial Comments of NASUCA in FERC Transmission 'Building the Future" NOPR RM21-17-000, August 17, 2022

[3] Post-Technical Conference Comments of NASUCA in Dockets AD-22-8-000 and AD-21-15-000, March 23, 2023

[4] Initial Comments of NASUCA in FERC Transmission 'Building the Future" NOPR RM21-17-000, August 17, 2022

[5] Gov. Pritzker Vetoes Legislation – Amendatory Veto to Illinois House Bill 3445, August 16, 2023

NATIONAL ASSOCIATION OF STATE UTILITY CONSUMER ADVOCATES
RESOLUTION 2022-01

URGING DEVELOPMENT OF CONSUMER PROTECTION POLICIES FOR INTERCONNECTION AND ELECTRIC TRANSMISSION AND DISTRIBUTION PLANNING AND DEVELOPMENT

Whereas, electric service is an essential service; and

Whereas, consumers' lives and livelihoods depend on such service being safe, reliable, and affordable; and

Whereas, the electric system exists to serve customers; and

Whereas, consumers ultimately both pay for the costs of any generation, transmission, and distribution development and bear the brunt of impacts if the lights go out; and

Whereas, the electric system must be well-planned for consumer system demands and needs and be based on cost-efficient planning principles, and the planning process must provide for the opportunity for meaningful input by consumers; and

Whereas, increased interconnection of distributed energy resources can impact system requirements; and

Whereas, electric system infrastructure must be able to withstand extreme weather events; and

Whereas, stronger interregional connections can help increase overall electric system reliability and resilience; and

Whereas, transmission and distribution investment is necessary and advantageous for the electric system to meet reliability and public policy climate objectives, and in particular, to allow the interconnection of non-fossil fuel generation resources; and

Whereas, competitive bidding for transmission services should result in greater innovation and lower prices for consumers. In addition, competitive bidding should improve operating efficiencies and will shift business risk from monopoly customers to competitive transmission providers. Competition for transmission services should enhance service quality, should make the winning providers more responsive to consumer needs, and should increase owner accountability to consumers and regulators; and

Whereas, grid-enhancing technologies can help offset the need for infrastructure investment; and

Whereas, existing infrastructure should be used in future planning and development when it is in the best interest of customers to do so; and

Whereas, significant investment comes with significant responsibility because many consumers are already facing economic or environmental disadvantages and/or already escalated transmission charges; and

Whereas, individuals will bear the burdens of these investments, including societal, environmental, and economic impacts on our communities from siting facilities; and

Whereas, NASUCA members are concerned that FERC could over broadly define benefits as a method of unreasonable or unfair cost socialization; and

Whereas, NASUCA acknowledges that its individual member states have different policy priorities and different approaches to achieve those policy priorities; and

Whereas, adequate consumer protections are essential to any process reforms; and

Whereas, generator interconnection and transmission and distribution development policies must be prepared to address not only interregional issues of large generation sited farther from the customers it will serve, but the inverse issue of increased interconnection of distributed energy resources sited near load or behind the meter.

Now, therefore, be it resolved, the National Association of State Utility Consumer Advocates ("NASUCA") supports policy changes to ensure that the future grid is designed appropriately and cost-efficiently to ensure service remains reliable and resilient, rates remain just and reasonable, and competition remains a priority, but cautions that policies should only be changed if the outcomes benefit customers and finds that the following principles are essential to ensuring that interconnection, and transmission and distribution development plans and policies both benefit and protect customers:

1. Any changes to policies and rules impacting transmission and distribution development should be made in an open and transparent manner that allows for ongoing public input.

2. Cost-causation regulatory principles should be followed to protect consumers from paying charges for transmission services that do not provide benefits to those consumers.

3. Cost allocation must reflect the distribution of costs and benefits associated with projects. Cost causation principles require that the entities paying the costs benefit from the investment and that their share of costs is commensurate with the benefit that they receive.

4. The methods for calculating and assigning benefits should be based on objective, measurable, clear, and specific metrics, and such metrics should be developed in concert with the consumers who may ultimately pay those costs.

5. Transmission and distribution plans should be based on reasonable, transparent, and well-tested planning assumptions (e.g., vetted by state regulatory processes), shared with the representatives of those who are impacted by the planning decisions, informed by feedback from the public, developed with consideration given to alternative solutions, forward-looking, and holistic in that they consider multiple needs;

6. Consumer advocate groups should have support to participate actively in regional transmission planning processes;[1]

7. Consumers should be protected from unreasonable costs and risks. Poor planning can lead to imprudent transmission and interconnection, unnecessary spending, poorly-sited transmission facilities, and stranded assets that are not used and useful in the provision of

[1] For example, the Consumer Advocates of the PJM States (CAPS), http://www.pjm-advocates.org/, is funded through the PJM budget.

utility service. Neither these risks nor the associated costs should be passed onto consumers.

8. Energy infrastructure has sometimes been sited in economically, socially, and environmentally disadvantaged communities. Planning should be sensitive to the local experience of communities where transmission may be located and should include considerations of whether the project development would exacerbate existing inequities.

9. Transmission planning processes should be robust to optimize siting in areas of highest economic, social, and network value; network planning should be holistic and incorporate both expected generation development and consumer demand projections.

10. Network planning should account for the severity of environmental and weather conditions, including hurricanes, tornadoes, storms, fires, and other natural disasters.

11. Network planning should examine cost-effective alternatives to infrastructure development including the siting of distributed generation and the use of grid enhancing technologies.

12. The principle of used/useful should remain the core of transmission policies and customers should not be required to bear the costs of plant that does not go in-service.

13. Transmission incentives under FERC Order 679 should not be granted where there is no need or justification for such incentives, where projects would be built absent an incentive, and where such incentives only serve to unnecessarily increase the cost of building needed transmission for consumers. To the extent incentives are offered, they should be accompanied by cost protections, including time- and scope-limits to ensure that consumers are charged only for the incentive necessary to incent the development of a needed project that would not be built absent the incentive.

14. The initial risks of bidding and planning for projects should be borne by the developer, not the customers, and developers should not be allowed to pass on to consumers the planning costs of projects that bid into but are not chosen for regional transmission plans as these costs are traditional business risks.

15. As appropriate, generators and/or developers should continue to pay some or all interconnection costs because they are the primary beneficiary of the activity: interconnection is a necessary component to bringing power to the market/load.

16. Federal transmission planning cost allocation and generator interconnection policies should be complementary to and not supplant state jurisdiction over regional resource planning decisions.

17. Federal and state jurisdiction should be clearly defined so that there is no regulatory gap and so that all projects receive regulatory scrutiny of their need, prudence, and costs.[2] The Utility should bear the burden of proof that transmission facilities are properly included in a FERC-approved tariff before the utility charges consumers.

18. States, as appropriate, should retain the primary authority and control over the siting of transmission facilities. Transmission lines in national transmission corridors and elsewhere can and should include an evaluation of the costs and benefits of the proposed transmission project to consumers of that state, and to the extent transmission is regionally planned, there should be a robust process for state input into transmission siting and cost allocation decisions.

19. Regional transmission planning should incorporate and support, rather than supplant or undermine, state policies. Because states are charged not only with regulating their share of the energy industry but also with looking after the safety, health, and welfare of their citizens, energy development is but one consideration in a larger set of considerations for the state. Federal policies that supplant state policies may lead to unintended consequences for other important areas of state responsibility.

20. Planning policies should be nimble enough to account for regional, state, and local considerations because there are regional, state, and even local differences in policies, consumer growth, generation mix, and community impacts that dictate the tailoring of policies to the specific needs of the area. Relatedly, the need for change differs by area, and not every region necessarily needs a complete transformation in its transmission planning and cost allocation policies.

21. Some but certainly not all NASUCA members' regions are served by a regional transmission organization or an independent system operator (hereafter, collectively referred to as "RTOs"). For those states where a utility or utilities are part of an RTO, those RTOs and state and federal officials should ensure that there is an independent entity within each jurisdiction that is charged with reviewing interconnection concerns and complaints.

22. Many NASUCA members are interested in exploring the creation of Independent Transmission Monitors in both RTO and non-RTO regions. Like Independent Market Monitors, the Transmission Monitors should be attuned to the specific needs of, and data associated with, the regions that they oversee.

23. Planning principles should support competition in the building of RTO-identified transmission projects. Competition helps ensure the adoption of efficient, cost-effective

---

[2] A 2019 report prepared for the Consumer Advocates of the PJM States found that capital expenditures for supplemental projects— projects not required for compliance with PJM operational performance, system reliability, or economic criteria—increased by more than 1,000% from 2013 through 2020. *See* Continuum Associates, Expert Consultation on PJM Supplemental Transmission Projects: Standards and Oversight 1, September 13, 2019, https://0201.nccdn.net/4_2/000/000/076/de9/final-report---caps---pjm-supplemental-transmission-projects_wo_.pdf; *see also* PJM, TEAC Project Statistics, May 12, 2020, Slide 6, https://pjm.com/-/media/committees-groups/committees/teac/2020/20200512/20200512-item-10-2019-project-statistics.ashx

solutions that lead to lower prices for consumers. FERC's transmission planning and interconnection policies should continue to support robust competition and should temper the ability of incumbent transmission providers to expand their monopoly control over the electric grid.

24. In states or regions in which incumbent transmission providers are insulated from competition, FERC must establish processes to ensure that transmission plans are cost-effective and transmission development costs are reasonable, carefully managed, and more frequently reviewed to ensure the transmission projects are still needed and cost justified.

25. Transmission planning should be data driven and should support concepts of just and reasonable rates and the prevention of undue discrimination.

26. Effective and early public participation is necessary so that transmission planners can understand the impacts of their decision-making on the public.

27. Federal Agencies should work together to streamline transmission siting on Federal lands.

Be it further resolved, that NASUCA authorizes its Executive Committee to take appropriate actions consistent with the terms of this resolution. The Executive Committee shall advise the membership of any proposed action prior to taking such action, if possible. In any event, the Executive Committee shall notify the membership of any action taken pursuant to the resolution.

Submitted by the Electric Committee

Approved:

2022 NASUCA Mid-Year Meeting

June 12, 2022

ORAL TESTIMONY
MARC L. SPITZER
AB 470 - 10/10/2023
Wisconsin State Legislature

Intro

Mr. Chairman, Members, my name is Marc Spitzer. I represent the Edison Electric Institute, though the views I express today on the ROFR Bill are my own.

I am a visitor to Wisconsin and a guest in this chamber. As a former state legislator in Arizona, I recognize each jurisdiction is unique. I'm here today mindful this Legislature will ultimately decide what's best for Wisconsin.

Two overarching observations. First, as in Arizona, Wisconsin has harnessed the benefits of competition in wholesale power sales without disrupting operation of the grid. Secondly, the Legislation before the Committee is necessary because competitive procurement for transmission has not been the magic bullet. Elimination of the federal ROFR in Order 1000 has led not to more wires but instead bureaucratic morass. In that respect I was mistaken when I supported it.

I left the State Senate to run for the Arizona Commission in 2000 when California's failed deregulation scheme cratered the entire western power grid. Between my election in November 2000 and taking the Oath as Commissioner in the new year, they had been counting hanging chads in Florida and Energy Secretary Richardson was threatening to appropriate Arizona electricity to keep the lights on in San Francisco.

Unlike California's deregulation fiasco , Wisconsin presents a success story. This Legislature had the foresight in 1999 to enact Legislation establishing ATC as an independent company responsible for transmission for much of the state—one of the first transmission-only utilities in the country. Wisconsin was a leader in pursuing open-access transmission and tasked ATC to construct, operate, maintain, and expand transmission to ensure reliable and affordable electricity service for Wisconsin.

I'm now going to address the issue of competition head on. During my 41 years as attorney and 20 years in public service I have been advocate for the free market. The economic form of competition, however, varies with each specific business application and even among industry segments. For example, agricultural commodities have moved towards market forces but retain both federal and state regulation and tax preferences.

Competition was introduced into energy markets beginning in the 80's to the great benefit of consumers. U.S. natural gas markets are the envy of the world, and the decontrol of wellhead prices led directly to the shale revolution and billions of dollars in savings. There remain, however, many limitations on pure competition in electricity. For example, Congress required nuclear power plants be owned and operated by U.S. companies.

I have been a strong supporter of competition in power generation and while Legislator and Commissioner oversaw merchant power plant construction that kept Arizona's lights on and rates down. However, electric *transmission* is a much different business proposition than power generation.

The ROFR bill before this Committee recognizes the unique challenges of running high voltage power lines through peoples' back yards.

This is not any easy task. Mr. Chairman, please indulge me in a point of personal privilege. When this Legislature launched ATC, Mr. José Delgado was selected to, as he put it, "elect poles and wires to public office in Wisconsin." Wisconsin's grid went from worst to first. Like many refugees from Castro's Cuba, José was immensely proud of his adopted country, moving to Wisconsin and starting as a journeyman electrical engineer. While serving on the Federal Energy Regulatory Commission I presided over a meeting to deal with the 2008 financial crisis's impact on the power grid, and it was José Delgado who calmed down a room of nervous stakeholders by saying *"don't bet against the United States."*

Let me echo that. In continuing the legacy of what this Legislature put in place—and what José led—what's important to keep in mind is *"don't bet against Wisconsin."* Because when it comes to "competitive bidding" for transmission—that's betting against Wisconsin. That's betting that faraway companies will reliably provide affordable transmission, even though their record reflects just the opposite.

Allowing this bidding process is gambling with the transmission system this Legislature created two decades ago. You and your predecessors deserve praise for Wisconsin's prior leadership on transmission—now, though, without a ROFR, Wisconsin lags behind several other states in the region that have ROFRs.

It's time to take this next step to further that legacy of reliable and affordable power for all Wisconsinites. The ROFR Bill before the Committee is not about abstractions. Energy is the lifeblood, not only of our economy, but of our way of life. The ROFR will help put wires in place so electricity will, as it has for 100 years, continue to flow.

Background

Here's how I came to view the ROFR as essential in building more reliable and affordable transmission.

In 2006, I was appointed to be a Commissioner of the Federal Energy Regulatory Commission, FERC.

At the time, I believed competitive solicitation might lead to more interstate transmission.

As part of a larger effort to reform transmission policy in 2011, FERC issued Order 1000, eliminating the ROFR in certain FERC-regulated contexts but preserving states' ability to enact ROFRs. You'll hear people speculate today about FERC and Order 1000, but *I was there*—and, having hope in the theory of competitive transmission, I voted for Order 1000. I have reconsidered my views on the ROFR because Order 1000, despite the best intentions, has not resulted in a more robust electric grid. Instead, and for many reasons, Order 1000 led to lots of meetings and emails but very few wires.

It's now clear—with the benefit of over a decade of actual experience and new expert studies analyzing this period—that competitive bidding has failed to deliver. It has not caused more transmission to be built. It has not lowered costs.

Hindsight is 20/20. And what I can see clearly now is that with Order 1000, what was well-intended has spun into a series of endless procedures that have not ultimately delivered more transmission. Competitive bidding has unfortunately ended up hand-cuffing local companies that wanted to actually build—preventing them from getting real things done.

There's that old quip, where an economist might ask, "sure, the idea doesn't work in practice, but does it work in theory?" That's essentially what the opponents of the ROFR are saying—after more than a decade of evidence that competitive bidding doesn't work in practice, that somehow, *in theory*, competition works. But that hasn't been borne out on the ground.

Reliability

What's rightly at the top of everyone's minds as we consider electric policy is making sure the lights stay on.

As recent weather events and the pandemic have made painfully clear, reliable transmission has never been so important to keeping our communities safe and protecting local businesses. It supplies the lifeblood not only of our economy but our daily lives.

Competitive bidding jeopardizes reliability. The delays inherent in the competitive solicitation process present significant reliability concerns because it takes longer for key lines to start serving customers. Adding developers also makes the grid more brittle by exposing it to new vulnerabilities. Some competitive developers have solid records across the country. Others, however, have neither produced nor distributed a kilowatt-hour of electricity in Wisconsin or anywhere else.

With a ROFR law, the companies with a record of proving reliable service are the ones who build essential power lines. When constructing a line, they can rely on substantial expertise and experience operating in Wisconsin. They know the land. They have relationships with local businesses that cost-effectively supply them with necessary materials. They're available and on the ground when the wind blows and the snow falls. And their hardworking linemen live in the communities they serve.

In short, this Legislature has established a system that enables local companies to build reliable transmission. Allowing these companies a first crack at new lines helps Wisconsin play to its strengths.

Costs

Beyond reliability, competitive bidding has not led to cost savings.

If competitive solicitations *did* present cost savings opportunities, we'd know by now. There would be hard evidence. But the data—well, that points in the other direction.

In particular, the transmission experts at Concentric have put together excellent reports analyzing, in painstaking depth, competitive transmission solicitations. I really recommend taking a look.

Let me tell you the key points. In some cases, competitively-bid project costs have skyrocketed against the initial estimates as developers circumvent cost caps. In other cases, final costs were close to other proposals—raising the question of whether the competitive solicitation itself actually resulted in materially lower prices.

For the competitive bidding to be efficient and good policy, it would need to be true that the cost of preparing the bids and administering the selection process did not exceed any construction savings. But given the effort needed in the solicitation process, it's not clear that this is often the case. Indeed, these costs from the process itself may ultimately be passed on to ratepayers.

And why haven't cost savings come to pass? Substantial cost overruns have occurred because of outside events that might have been *avoided* by local transmission companies, such as regulatory delays, re-routing, and environmental challenges. The developers often lack the cost advantages that local companies have, like expertise and experience on the ground, economies of scale, and local teams of engineers. Remember—if this bill were enacted and a local transmission company were to build a line, it would be required to procure key goods and services in competitive markets to keep costs low.

Delays

As has become clear, delays have been a major problem stopping competitive bidding from improving reliability or lowering costs. Competitive bidding causes two kinds of delays. First, delays are caused by the added layer of bureaucracy from the competitive process—and all the endless meetings and documents it involves. Local transmission companies are able to put steel in the ground following confirmation of the need. But the competitive solicitation process, when used, usually delays construction by a year or two.

Second, developers of competitively-bid projects often face delays from planning and construction issues. On average, the projects that Concentric examined were delayed about a year beyond the required in-service date.

So now, when you hear ROFR opponents say, "if local companies are so effective, why not let them compete with everyone else?" the key issue isn't just that allegedly low bids from independent developers come in and then costs balloon, and construction deadlines expand. It's that even if the local company is selected in the competitive process, Wisconsin is already behind the eight ball because the process itself takes a year or two.

Example

I'll tell just one story of a competitively solicited project I'm familiar with from my home state, Arizona.

The line is to start in California and stretch into La Paz and Maricopa Counties in Arizona. The California grid operator began the competitive solicitation about a decade ago in 2014. The winning bid came in with a cost cap of about $240 million dollars. But costs ballooned and now the developer is seeking around $550 million dollars in cost recovery, more than double the original cost cap.

When the process began in 2014, the in-service date was in early 2020. Spoiler alert: it's still not in-service. The current estimate is for 2024.

Commenting on this debacle, FERC Commissioner Mark Christie noted quote "There are those who think that competitive bidding is a 'magic bullet' … Think again."

If I were to continue the analogy, I'd say far that from a magic bullet, competitive bidding has been a dud. Local transmission companies, on the other hand, would have been better able to anticipate and head-off regulatory and other challenges that caused these cost overruns and delays in Arizona. With all the debate and bureaucracy inherent in the competitive solicitation process, building this line has taken too long and costs have risen. It's not that there's wrongdoing on the part of the developer, it's just a matter of looking back years later and coming to the understanding that competitive solicitation was not the salve to what ails transmission development.

Conclusion

This Bill presents an opportunity for affordable and reliable power in Wisconsin. This Legislature acted in 1999 to the benefit of Wisconsin. A ROFR would build on that success. I respectfully support favorable consideration by this Committee.

WPPI ENERGY

1425 Corporate Center Drive Sun Prairie, WI 53590-9109 608.834.4500 wppienergy.org

Good afternoon, Chairman Steffen, Vice Chair Summerfield and members of the Assembly Committee on Energy and Utilities, my name is Joseph Owen and I am the Director of Government Affairs for WPPI Energy. Thank you for the opportunity to testify in support of Assembly Bill 470.

WPPI Energy is a member-owned, not for profit joint action agency that provides wholesale energy, services, and advocacy to 41 public power utilities covering 32 Assembly districts across the State of Wisconsin. Our members, one of whom is here with me today, keep the lights on in the small to medium sized cities and villages they serve and answer directly to their friends and neighbors in those communities.

Unlike other joint action agencies across the country, WPPI Energy is fortunate to own transmission through our partial ownership of ATC. Prior to ATC's formation, we needed to negotiate for transmission access rights across multiple jurisdictions to bring the energy needed to serve our members to their communities. This is still the case for many of our peers across the country. Our support for AB 470 is based on a simple premise: WPPI and our public power members benefit in two distinct ways when ATC builds transmission lines.

First, because of our partial ownership in ATC, we are able to offset the costs associated with moving energy across the power grid with the payment we receive for our fractional ownership of ATC transmission assets, and we pass both the costs and the savings along to our members. **That would not be the case with a transmission line built by an out of state, merchant transmission company where we would incur costs from moving energy, but have no earnings offset.** The savings provided to our members because of WPPI's participation in ATC are significant: over the past three years (2020-2022) the savings have averaged over $9M per year. This bill would ensure that WPPI's ability to offset the cost of delivering electricity to our public power members, and ultimately their customers, is preserved for future transmission lines MISO determines are needed to promote electric grid stability.

Second, ATC is in the transmission business for the long term. It is invested in and responsive to Wisconsin communities, businesses, and stakeholders. If WPPI has any issues in delivering our generation resources to our load that could solved by transmission solutions, we know exactly who to call at ATC. They are always responsive and collaborative in seeking beneficial outcomes. ATC is laser-focused on providing safe and reliable electricity to Wisconsinites year after year. They are not here today on one big project and gone tomorrow with no lasting concern over the approach taken to build a single project. This bill would ensure a Wisconsin company employing men and women from across the state continues to build the critical infrastructure needed to provide reliable energy to all Wisconsinites. ATC is a trusted, Wisconsin-based partner providing a critical service and this benefits all WPPI public power members.

Thank you for the opportunity to testify today on this important legislation.

Shawano
Municipal
Utilities

Shawano Utilities Testimony in SUPPORT of AB 470: Incumbent transmission companies Right of First Refusal to maintain, own, and construct certain transmission facilities.

Chairman Steffen, Vice-Chair Summerfield and members of the Assembly Energy and Utilities Committee,

Thank you for the opportunity to testify **in support** of AB 470 today. My name is Bruce Gomm and I am the General Manager of Shawano Municipal Utilities (SMU).

Shawano Municipal Utilities was established in 1900 and serve more than 6,000 electric customers in the Shawano area and along with Clintonville are owners of Badger Power Marketing Authority of Wisconsin. I have been the General Manager of Shawano Municipal Utilities since January of 2023.

I am here in support of AB 470 because it will save Shawano Municipal Utilities' customers money and ensure that our critical electric energy infrastructure will be constructed and managed by Wisconsin-based companies who have a history of providing reliable and safe energy transmission for distribution to our customers.

As an owner of American Transmission Company (ATC) Badger Power Marketing Authority has received over $4.3 Million dollars in distributions over the past 10 years which we have been able to use for reinvestment, improvements to our distribution network, and community support just to name a few examples, all benefits our customers. We would not see any distributions from projects built by an out-of-state company.

As a public power community, we are proud to provide reliability to our residential, commercial, and industrial customers that we serve. Passage of this bill will ensure that major transmission projects will be Wisconsin-owned and overseen by Wisconsin regulators, which means, generally, projects that are approved and completed sooner and more cost-effectively than those overseen by DC regulators. Again, all at a benefit to our local residents and businesses.

Finally, I don't think it can be overstated enough, our engagement and partnerships with Wisconsin-based companies. They are constantly preparing and planning for our needs and in turn the needs of our customers, we have trusted working relationships with ATC and know who to call if there is a problem and know that it will be handled quickly and give us timely and accurate information that we can communicate to our customers.

Thank you for your time and your support of AB 470.

122 N Sawyer St. □ PO Box 436 □ Shawano, WI 54166-0436 □ Phone (715) 526-3131 □ Fax (715) 524-3708

Sun Prairie Utilities
Est. 1910
P.O. Box 867 • 125 West Main Street • Sun Prairie, Wisconsin 53590
P: 608.837.5500 F: 608.825.6001 W: sunprairieutilities.com

Good afternoon Chairman Steffen, Vice Chair Summerfield and members of the Assembly Committee on Energy and Utilities.

My name is Rick Wicklund and I am the Utility Manager at Sun Prairie Utilities. Thank you for the opportunity to testify today in support of Assembly Bill 470. Sun Prairie Utilities is a municipal electric utility founded in 1910. We provide electric service to over 17,000 customers and joined WPPI Energy in 1989. I serve on the WPPI Energy Board of Directors and also as the MEUW Board Chair.

Like those up here with me, I support the passage of AB 470 because it will save Sun Prairie Utilities' customers money and will help ensure we can continue to provide the safe and reliable electricity our customers expect.

Sun Prairie Utilities receives all the power we provide to our customers from WPPI Energy. Because both WPPI and Sun Prairie Utilities have an ownership stake in ATC, our power costs, which include generation and transmission, are lowered from the receipt of transmission revenues that offset the cost of delivering electricity to our city. In fact, last year we estimate our cost savings to be $817,000 dollars. These savings reduce the electricity costs to the residents and businesses that Sun Prairie serves. All people that live in WPPI's 41 Wisconsin member municipalities, and the businesses and industries located in those communities, similarly benefit from WPPI's participation in ATC. These savings to WPPI public power communities would not occur if new transmission facilities were owned by out-of-state transmission developers.

Finally, ATC is a trusted partner that we at Sun Prairie Utilities are comfortable working with. ATC is engaged with its customers – routinely and frequently seeking input on future transmission needs and ideas about the most cost-effective solutions to those needs. ATC's interests are aligned well with those of its customers, and it provides excellent value as a result. In my experience, ATC does all the seemingly small things well – tree trimming, pole inspections, and line maintenance that ensure reliable transmission service. And in the rare case where service interruptions occur, ATC has proven to be easily accessible to assist in the best, quickest manner to get service restored to our customers. We view this as a great value having an in-state partner we can call on a moment's notice.

Thank you for your time and attention to this important matter.

Municipal Electric Utilities of Wisconsin
725 Lois Drive
Sun Prairie, WI 53590
T: 608-837-2263
www.meuw.org

Municipal Electric Utilities of Wisconsin Testimony in SUPPORT of AB 470: Incumbent transmission companies Right of First Refusal to maintain, own, and construct certain transmission facilities.

Chairman Steffen, Vice-Chair Summerfield and members of the Assembly Energy and Utilities Committee,

Thank you for the opportunity to testify **in support** of AB 470. I am Tyler Vorpagel, Director of Legislative and Regulatory Relations for the Municipal Electric Utilities of Wisconsin. The Municipal Electric Utilities of Wisconsin (MEUW) is a 95-year-old trade association representing Wisconsin's 81 municipally owned - not for profit - utilities, their employees, and customers. MEUW's members are responsible for the safe, reliable, and low-cost delivery of electricity to over 300,000 customers across 43 counties in Wisconsin.

When American Transmission Company (ATC) was formed in the early 2000's as the first multi-state, transmission-only utility in the United States, our municipal utility members who owned their own transmission assets, turned those assets over to ATC in exchange for a fractional ownership percentage. MEUW has 15 members who are owners of ATC (one of which is with me today – Bruce Gomm from Shawano Utilities, Shawano is a joint owner of Badger Power Authority) and another 32 who benefit by purchasing their power from WPPI Energy.

Because municipally owned utilities are not-for-profit and are funded exclusively with ratepayer dollars – not taxpayer dollars – our members and their customers benefit from Wisconsin-owned transmission companies building this infrastructure. Over the past 10 years ATC has distributed more than $197 Million to public power utilities in Wisconsin, that is real money that goes back into system improvements and results in keeping customer rates down. These utilities will receive $0 in distributions from any project in Wisconsin built by an outside party.

Reliability is extremely important to our customers. Customers of public power communities are without power less often and when an outage does happen, customers call a local number and community-owned utilities are prepared to act quickly and respond to safely restore power. The same is true for electric transmission in Wisconsin, passing this bill would ensure that our members will be served by Wisconsin-owned partners who have a demonstrated track record of safety, reliability, and communication and not an out-of-state owner.

Passage of AB 470 is important and strongly encouraged by your public power communities.

Thank you!

Wisconsin Public Power Utility Owners of American Transmission Company

- Algoma Utility Commission
- Columbus Utilities
- Kaukauna Utilities
- Manitowoc Public Utilities
- Marshfield Utilities
- Oconto Falls Municipal Utilities
- Plymouth Utilities
- Reedsburg Utility
- Sheboygan Falls Utilities
- Stoughton Utilities
- Sturgeon Bay Utilities
- Sun Prairie Utilities
- Wisconsin Rapids Utilities
- Badger Power Authority
    - Shawano Municipal Utilities
    - Clintonville Utilities

WPPI ENERGY

1425 Corporate Center Drive Sun Prairie, WI 53590-9109 608.834.4500 wppienergy.org

Good afternoon, Chairman Steffen, Vice Chair Summerfield and members of the Assembly Committee on Energy and Utilities, my name is Joseph Owen and I am the Director of Government Affairs for WPPI Energy. Thank you for the opportunity to testify in support of Assembly Bill 470.

WPPI Energy is a member-owned, not for profit joint action agency that provides wholesale energy, services, and advocacy to 41 public power utilities covering 32 Assembly districts across the State of Wisconsin. Our members, one of whom is here with me today, keep the lights on in the small to medium sized cities and villages they serve and answer directly to their friends and neighbors in those communities.

Unlike other joint action agencies across the country, WPPI Energy is fortunate to own transmission through our partial ownership of ATC. Prior to ATC's formation, we needed to negotiate for transmission access rights across multiple jurisdictions to bring the energy needed to serve our members to their communities. This is still the case for many of our peers across the country. Our support for AB 470 is based on a simple premise: WPPI and our public power members benefit in two distinct ways when ATC builds transmission lines.

First, because of our partial ownership in ATC, we are able to offset the costs associated with moving energy across the power grid with the payment we receive for our fractional ownership of ATC transmission assets, and we pass both the costs and the savings along to our members. **That would not be the case with a transmission line built by an out of state, merchant transmission company where we would incur costs from moving energy, but have no earnings offset.** The savings provided to our members because of WPPI's participation in ATC are significant: over the past three years (2020-2022) the savings have averaged over $9M per year. This bill would ensure that WPPI's ability to offset the cost of delivering electricity to our public power members, and ultimately their customers, is preserved for future transmission lines MISO determines are needed to promote electric grid stability.

Second, ATC is in the transmission business for the long term. It is invested in and responsive to Wisconsin communities, businesses, and stakeholders. If WPPI has any issues in delivering our generation resources to our load that could solved by transmission solutions, we know exactly who to call at ATC. They are always responsive and collaborative in seeking beneficial outcomes. ATC is laser-focused on providing safe and reliable electricity to Wisconsinites year after year. They are not here today on one big project and gone tomorrow with no lasting concern over the approach taken to build a single project. This bill would ensure a Wisconsin company employing men and women from across the state continues to build the critical infrastructure needed to provide reliable energy to all Wisconsinites. ATC is a trusted, Wisconsin-based partner providing a critical service and this benefits all WPPI public power members.

Thank you for the opportunity to testify today on this important legislation.

WPPI Member Communities in Wisconsin:

Algoma, Black River Falls, Boscobel, Brodhead, Cedarburg, Columbus, Cuba City, Eagle River, Evansville, Florence, Hartford, Hustisford, Jefferson, Juneau, Kaukauna, Lake Mills, Lodi, Menasha, Mt. Horeb, Muscoda, New Glarus, New Holstein, New London, New Richmond, Oconomowoc, Oconto Falls, Plymouth, Prairie du Sac, Reedsburg, Richland Center, River Falls, Slinger, Stoughton, Sturgeon Bay, Sun Prairie, Two Rivers, Waterloo, Waunakee, Waupun, Westby, Whitehall

Shawano
Municipal
Utilities

Shawano Utilities Testimony in SUPPORT of AB 470: Incumbent transmission companies Right of First Refusal to maintain, own, and construct certain transmission facilities.

Chairman Steffen, Vice-Chair Summerfield and members of the Assembly Energy and Utilities Committee,

Thank you for the opportunity to testify **in support** of AB 470 today. My name is Bruce Gomm and I am the General Manager of Shawano Municipal Utilities (SMU).

Shawano Municipal Utilities was established in 1900 and serve more than 6,000 electric customers in the Shawano area and along with Clintonville are owners of Badger Power Marketing Authority of Wisconsin. I have been the General Manager of Shawano Municipal Utilities since January of 2023.

I am here in support of AB 470 because it will save Shawano Municipal Utilities' customers money and ensure that our critical electric energy infrastructure will be constructed and managed by Wisconsin-based companies who have a history of providing reliable and safe energy transmission for distribution to our customers.

As an owner of American Transmission Company (ATC) Badger Power Marketing Authority has received over $4.3 Million dollars in distributions over the past 10 years which we have been able to use for reinvestment, improvements to our distribution network, and community support just to name a few examples, all benefits our customers. We would not see any distributions from projects built by an out-of-state company.

As a public power community, we are proud to provide reliability to our residential, commercial, and industrial customers that we serve. Passage of this bill will ensure that major transmission projects will be Wisconsin-owned and overseen by Wisconsin regulators, which means, generally, projects that are approved and completed sooner and more cost-effectively than those overseen by DC regulators. Again, all at a benefit to our local residents and businesses.

Finally, I don't think it can be overstated enough, our engagement and partnerships with Wisconsin-based companies. They are constantly preparing and planning for our needs and in turn the needs of our customers, we have trusted working relationships with ATC and know who to call if there is a problem and know that it will be handled quickly and give us timely and accurate information that we can communicate to our customers.

Thank you for your time and your support of AB 470.

122 N Sawyer St. □ PO Box 436 □ Shawano, WI 54166-0436 □ Phone (715) 526-3131 □ Fax (715) 524-3708

Sun Prairie Utilities Est. 1910
P.O. Box 867 • 125 West Main Street • Sun Prairie, Wisconsin 53590
P: 608.837.5500 F: 608.825.6001 W: sunprairieutilities.com

Good afternoon Chairman Steffen, Vice Chair Summerfield and members of the Assembly Committee on Energy and Utilities.

My name is Rick Wicklund and I am the Utility Manager at Sun Prairie Utilities. Thank you for the opportunity to testify today in support of Assembly Bill 470. Sun Prairie Utilities is a municipal electric utility founded in 1910. We provide electric service to over 17,000 customers and joined WPPI Energy in 1989. I serve on the WPPI Energy Board of Directors and also as the MEUW Board Chair.

Like those up here with me, I support the passage of AB 470 because it will save Sun Prairie Utilities' customers money and will help ensure we can continue to provide the safe and reliable electricity our customers expect.

Sun Prairie Utilities receives all the power we provide to our customers from WPPI Energy. Because both WPPI and Sun Prairie Utilities have an ownership stake in ATC, our power costs, which include generation and transmission, are lowered from the receipt of transmission revenues that offset the cost of delivering electricity to our city. In fact, last year we estimate our cost savings to be $817,000 dollars. These savings reduce the electricity costs to the residents and businesses that Sun Prairie serves. All people that live in WPPI's 41 Wisconsin member municipalities, and the businesses and industries located in those communities, similarly benefit from WPPI's participation in ATC. These savings to WPPI public power communities would not occur if new transmission facilities were owned by out-of-state transmission developers.

Finally, ATC is a trusted partner that we at Sun Prairie Utilities are comfortable working with. ATC is engaged with its customers – routinely and frequently seeking input on future transmission needs and ideas about the most cost-effective solutions to those needs. ATC's interests are aligned well with those of its customers, and it provides excellent value as a result. In my experience, ATC does all the seemingly small things well – tree trimming, pole inspections, and line maintenance that ensure reliable transmission service. And in the rare case where service interruptions occur, ATC has proven to be easily accessible to assist in the best, quickest manner to get service restored to our customers. We view this as a great value having an in-state partner we can call on a moment's notice.

Thank you for your time and attention to this important matter.

DAIRYLAND POWER
COOPERATIVE

Dairyland Power Cooperative Testimony on Assembly Bill 470
Ben Porath, Executive Vice President, and Chief Operating Officer
Tuesday October 10, 2023

Good afternoon, Chairman Steffen and Members of the Assembly Committee on Energy and Utilities. Thank you for the opportunity to testify on Assembly Bill 470 .

I'm Ben Porath, Executive Vice President, and Chief Operating Officer for Dairyland Power Cooperative. I've worked at Dairyland Power for over 20 years and have direct, first-hand experience working on the development, construction, maintenance, and ownership of three Mid-Continent Independent System Operator (MISO) regionally cost-shared transmission lines in the State of Wisconsin in that time.

Dairyland Power Cooperative is a generation and transmission cooperative headquartered in La Crosse, WI, serving member distribution cooperatives in Wisconsin, Minnesota, Iowa, and Illinois. Dairyland provides the wholesale power supply and other services to 24-member distribution cooperatives and 27 municipal utilities in the Upper Midwest. This represents a population of over 700,000 people served across our four-state region. Dairyland owns, operates, and reliably maintains over 3,200 miles of transmission lines and over 350 substations located throughout our 44,500 square mile service territory. The majority of our owned and operated transmission lines are 161 kV and 69 kV. All of the substations Dairyland owns are at the 161 kV or 69 kV level. Dairyland does jointly own some 345 kV transmission line as tenants-in-common, but does not own any 345 kV substations in the state.

Dairyland is a member of MISO. This is an independent, not for profit, member-based organization that is responsible for operating the power grid across 15 states and Manitoba, Canada. MISO also coordinates with its members and stakeholders in planning the grid for the future.

As a local transmission owner/operator in Wisconsin, Dairyland has a long history, now over 80 years, of providing reliable and cost-effective service in Wisconsin. Dairyland is committed to growing and supporting our rural communities and member distribution cooperatives in the wholesale purchase and delivery of electricity.

As a cooperative, we have a unique business model. Our non-profit status and democratic cooperative business model allow for local governance by our member-consumer owners through the elected Board of Directors. Local ownership by Dairyland ensures the economic benefit of transmission ownership/operation flows back to our local rural energy consumers. Transmission revenues off-set costs of service which help generate stable rates for our member-consumers over time.

Dairyland has a strong history of working collaboratively to support the development, construction, and operation of the electric grid. Dairyland is a member of the Grid North Partners (GNP), the group formerly known as CapX 2020. Grid North Partners is the result of cooperatives, municipals and investor-owned utilities serving consumers in Minnesota coming together to build out the next generation of high voltage transmission lines for enabling renewable energy, reducing carbon emissions, and enhancing reliability. Included in this effort was the new power line from the Twin Cities to Rochester to La Crosse completed in 2016.

Dairyland has also collaborated with other utilities on the Badger Coulee regionally cost-shared transmission line and the on-going development of the Cardinal-Hickory Creek transmission project, which will also be regionally cost-shared once complete.

By participating in these high voltage transmission efforts, Dairyland brings a not-for-profit, low capital investment by borrowing capital directly from the USDA's Rural Utilities Service (RUS) and income-tax free cost benefits to the projects through a comparatively lower revenue requirement. Dairyland and our member distribution cooperatives also have existing utility right-of-ways and relationships with the rural landowners impacted by the future expansion projects subject to Assembly Bill 470. Local control of transmission projects by utilities such as Dairyland benefits rural residents, rural landowners and rural member-consumers that pay for at-cost electric service.

Today, I am here to testify regarding Dairyland's concerns and opposition to Assembly Bill 470 in its current form. We request an amendment to allow for the inclusion of all incumbent transmission owners in the construction, ownership, and maintenance of high voltage projects in Wisconsin.

First, Assembly Bill 470, as currently drafted, is bad for public power and rural electric cooperatives in western Wisconsin. Dairyland would support an amendment to this bill based on our concerns.

Second, this truly is an urban versus rural issue based on how Assembly Bill 470 is currently drafted.

Finally, I'll explain why Dairyland has concerns with the bill as drafted this session when our cooperative supported this bill in the previous legislative session.

As mentioned, Assembly Bill 470 is bad for public power as currently drafted. Assembly Bill 470 closely models Minnesota's right of first refusal, or ROFR, statute with which I have first-hand experience. Assembly Bill 470 provides an exclusive right for Wisconsin incumbent transmission facility owners to own, operate and maintain new high voltage transmission lines in the state. This right is conferred based on ownership rights in existing high voltage substations. Existing high voltage substations are the starting point and ending point for new high voltage transmission lines.

However, Assembly Bill 470 also introduces the concept of regionally cost-shared transmission lines. Under MISO's tariff rules, regionally cost-shared transmission lines apply only to transmission lines 300 kV and above. In July 2022, MISO introduced 18 new regionally cost-shared transmission projects totaling over $10 billion of investment in the Upper Midwest. All $10 billion of new regionally cost-shared transmission lines are 345 kV volt projects.

Dairyland does not own any 345 kV substations. Only two incumbent utilities in Wisconsin own all of the 345 kV substations, Xcel Energy and American Transmission Company. Assembly Bill 470, as currently drafted, would give exclusive rights to all new regionally cost-shared transmission lines to these two utilities. Dairyland would have no such rights.

Why does this matter? It matters because it shifts costs to rural consumers. All load serving utilities in MISO pay the for the cost of these regionally cost-shared transmission projects. While at the same time, the utilities that have the right to own, construct and maintain these new regionally cost-shared transmission lines earn a federally guaranteed rate of return on these projects. That return helps off-set the cost to their retail consumers.

Dairyland serves retail consumers through its Wisconsin member distribution cooperatives and municipal utilities it serves. Dairyland and its members pay the cost of these new regionally cost-shared transmission lines. Without a right to invest, there is no opportunity to earn the rate of return from these transmission lines that off-set costs to consumers.

This is bad for public power. It is that simple. But rather than raising an issue and opposing it outright, Dairyland would support an amendment that if a new regionally cost-shared transmission line crosses a Wisconsin county where a Dairyland member serves retail-consumer members, then Dairyland should have a right to sit at the table and negotiate a fair, reasonable share of the new project. Again, it's a simple concept, if the new regionally cost-shared transmission line impacts rural consumers and land-owners by crossing their properties and communities, then they should have the right to own a fair share to benefit from the federal and MISO policies on cost recovery. If the rural landowners are burdened with the infrastructure, then they should also have a right to invest in and own a fair share.

Second, this really is a rural versus urban issue. Historically, transmission lines were built to serve growing consumer demand for residential, commercial and industrial electric consumers. And those retail consumers paid for the cost of the transmission lines needed through their utility rates.

The for-profit utilities like Xcel Energy and American Transmission Company, through its load-serving utility owners, serve the higher density urban areas of the State. Dairyland and its member distribution cooperatives were originally formed as part of the New Deal legislation to electrify rural America and serve the rural population with its much lower consumer density and higher percentage of poverty.

Because of this, the for-profit utilities such as Xcel Energy and ATC built larger high voltage projects, such as 345 kV substation and transmission lines to serve their urban consumers. This made sense as those urban rate payers paid for those lines and substations.

Dairyland, serving the rural and less densely populated area did not need to build 345 kV infrastructure as Dairyland could serve its member consumers through 161 kV and 69 kV infrastructure. Dairyland's member consumer paid these costs.

This model existed from the 1950s through the early 2000s as the transmission grid was developed to serve growing consumer demand. The model then changed. Consumer demand, or load growth, leveled off and has been flat for well over a decade or more.

The new 345 kV high voltage transmission lines being proposed and built today are being built for federal and state public policy reasons, to enable and move renewable wind and solar energy from where it's produced to where its consumed and to reduce carbon dioxide emissions. As there is a public benefit to these policies across a large multi-state region, federal policy put forth by the Federal Energy Regulatory Commission, or FERC, and adopted through the MISO transmission tariff, require all consumers to pay for these new transmission lines.

To promote the development, construction, and maintenance of these new 345 kV transmission lines, FERC policy as adopted by MISO in its tariff as Multi-Value Projects, or MVPs, provides a financial incentive and federally guaranteed rate of return to the owner of these new projects and allows the cost to be regionally cost-shared across the entire MISO North footprint.

The 345 kV substations and transmission lines were originally built by for-profit utilities to serve their dense urban loads. Public power utilities like Dairyland did not need to build infrastructure to that scale to serve our less densely populated service areas. This is why the urban utilities own the 345 kV infrastructure and rural public power generally does not in this part of the Upper Midwest.

Now, when the expansion of regionally cost-shared transmission project at 300 kV or above is for Federal and State public policy reasons, renewable energy and carbon reduction, all end-use consumers pay the cost. However, in the current draft of Assembly Bill 470, only the urban rate payers of Xcel Energy and ATC would get the benefits conferred by federal policy on transmission incentives. Rural consumers would have to pay the cost while Assembly Bill 470, as drafted, would remove any right of ownership and cost recovery for rural public power.

To solve this fairness and equity concern, Dairyland supports the introduction of an amendment that would allow public power to negotiate a fair and reasonable share of these new regionally cost-shared transmission facilities to protect the interests of rural consumers.

Finally, I would like to address why Dairyland supported a similar bill in the previous session. Last session, the investor-owned utilities, provided assurances that the utilities would work together on regionally cost shared projects as we had previously in projects such as the CapX 2020 (Twin Cities to Rochester to La Crosse) 345 kV transmission line, the Badger Coulee (La Crosse to Madison) 345 kV transmission line, and the Cardinal Hickory Creek (Dubuque to Madison) 345 kV transmission line. Both the Badger Coulee and the Cardinal Hickory Creek lines are MISO MVP regionally cost-shared projects while the CapX 2020 project was not and was paid for by each utilities' rate payers. Due to the assurances provided about fair participation, Dairyland supported the previous session's bill.

What has changed since the previous legislative session is MISO released its project list of 18 new 345 kV transmission lines, which is a $10 billion portfolio of projects in July 2022. MISO is also working on a second project list of 345 kV projects in another announcement expected in 2024.

While ATC and Xcel Energy previously provided assurances to work together on these new regionally cost-shared projects, real-world experience proved otherwise. A specific example is that of the new 18 MISO 345 kV regionally cost-shared transmission projects includes a new Mankato to North Rochester, line segment in Minnesota. This new 345 kV line segment could not exist without the prior CapX 2020 Twin Cities to Rochester to La Crosse 345 kV transmission line project that built the new North Rochester 345 kV substation. While Dairyland was an investor and owner of the CapX 2020 345 kV transmission line, decisions were made that Xcel Energy would solely own the 345 kV North Rochester substation for NERC cyber security compliance reasons. Assurances were given that sole ownership of the substation was for cyber security reasons only and not related to the Minnesota ROFR statute which was signed into law at about the same time.

In 2022, after MISO released its project list of new 345 kV transmission line projects, Dairyland, Rochester Public Utilities and Southern Minnesota Municipal Power Agency, all public power entities, approached Xcel Energy to discuss line ownership of the Mankato to North Rochester line segment. Xcel Energy took the position that the Minnesota ROFR statute, based on end-point substation ownership, gave Xcel Energy exclusive rights to that new regionally cost-shared transmission line. Xcel Energy did not remember the assurances it gave in the CapX 2020 project and that it honored previously in the Badger Coulee project.

Thus, Xcel Energy proved to Dairyland that mere assurances are not enough when a ROFR statute confers, by the power of the state exclusive rights to own, construct and maintain new regionally cost-shared transmission lines and their resultant financial benefit.

As Dairyland has this first-hand experience in Minnesota with the application of a ROFR statute in, we cannot now support Assembly Bill 470 in Wisconsin for the very same reasons. Unless Assembly Bill 470 is amended to provide a fair opportunity for public power to have a seat at the table, this bill will negatively impact our consumer-members and other public power entities.

In closing, thank you Chairman Steffen for the opportunity to share the perspective from Dairyland Power Cooperative, and I am happy to answer questions from the Committee.

"Energy Through Excellence"
This institution is an EOE and provider

Dunn Energy Cooperative

N5725 600th Street, P.O. Box 220
Menomonie, WI 54751-0220
Phone: 715-232-6240
Toll Free: 800-924-0630
Fax: 715-232-6244
www.dunnenergy.com

October 10, 2023

Good afternoon, Chairman Steffen and Members of the Assembly Energy and Utilities Committee. My name is Jesse Singerhouse. I am the General Manager/CEO of Dunn Energy Cooperative in Menomonie, Wisconsin. There I work with a team of 27 dedicated employees to keep the lights on for over 10,000 accounts in our rural service territory. I've been with the Cooperative for 23 years, serving the last three as CEO. Dunn Energy is governed by a board of directors made up of members of the cooperative. As a cooperative we are guided by our principles to serve our member-owners and our communities. Dunn Energy is also a member-owner of Dairyland Power Cooperative. Dairyland supplies the energy needs for twenty-four electric distribution cooperatives, as well as twenty-seven municipal utilities in the upper Midwest. Dairyland Power is a member of MISO, the Mid-continent Independent System Operator.

I sincerely appreciate the opportunity to be with you today to express my opposition, on behalf of my rural members, to Assembly Bill 470 (AB 470) in its current form. I believe AB 470 has merit and an amendment should be developed that will create an option for ALL incumbent transmission owners in Wisconsin to invest in the construction, ownership, and maintenance of high voltage projects in our State. Wisconsin has a long history of working in a bipartisan fashion to develop energy policy that will safely deliver reliable, affordable, and environmentally responsible energy to rate payers across the state.

However, this legislation as written, shifts the cost recovery for these investments to rural members while only the urban customers and shareholders of for-profit utilities get to realize the financial benefits of these investments.

Committee members, October is Cooperative month. Each year we celebrate our truly unique business model and the seven cooperative principles. These principles help guide our approach to many business decisions we face. Two of those principles seem applicable as I looked at AB 470.

Cooperative principle number three is Member Economic Participation; meaning members invest in the cooperative to ensure its' long-term success. Members then see a return on their investment in the form of rates based on the cost of service and the return of their equity in the cooperative over time. If we apply this principle to AB 470, we only see half the equation. Dunn Energy members will economically participate in these valuable high voltage transmission projects through higher rates because MISO has determined them to be valuable to the entire region. But Dunn Energy members will not see an economic return on the capital they are putting forth. Yes, they will see a reliability benefit of expanding our transmission capacity within the State. But the economic return will not be seen by my members, only the expense.

The sixth cooperative principle is Cooperation Amongst Cooperatives; meaning cooperatives serve their members most effectively by working together. I know we are not talking about just cooperatives in relation to AB 470, but perhaps cooperative principle number six is a good reminder for all involved. Historically, we have seen strong cooperation amongst the utility partners in the state. Dairyland worked cooperatively with other utilities on both the Cap X and Badger Coulee projects as examples. Unfortunately, verbal assurances of working together on these new high value projects that benefit all rate payers in the State is not enough. As we have learned from recent experience the assurances of cooperation can change quickly. Some will argue that AB 470 will still allow participation from Dairyland Power and my rural members though negotiations and discussions. While that sounds great, we believe it is better to amend AB 470 to guarantee everyone gets an invitation.

If passed as drafted, AB 470 would not guarantee Dairyland Power Cooperative, and thus my rural members, a seat at the table in the development of critical transmission infrastructure in Wisconsin. It would only guarantee higher rates for my members and cost shifting to rural Wisconsin. I firmly believe that AB 470 should be amended to guarantee that every member in Wisconsin that is billed for these valuable transmission projects receives the same opportunity to invest in the projects and realize the return on investment.

What is the downside risk of including my members, who will be paying for these projects, in the initial investment? Will it cause the projects not to happen? Will it increase the cost of the projects? I strongly believe the answer is no. Will including them result in fairness to my members and other excluded members? Absolutely it will.

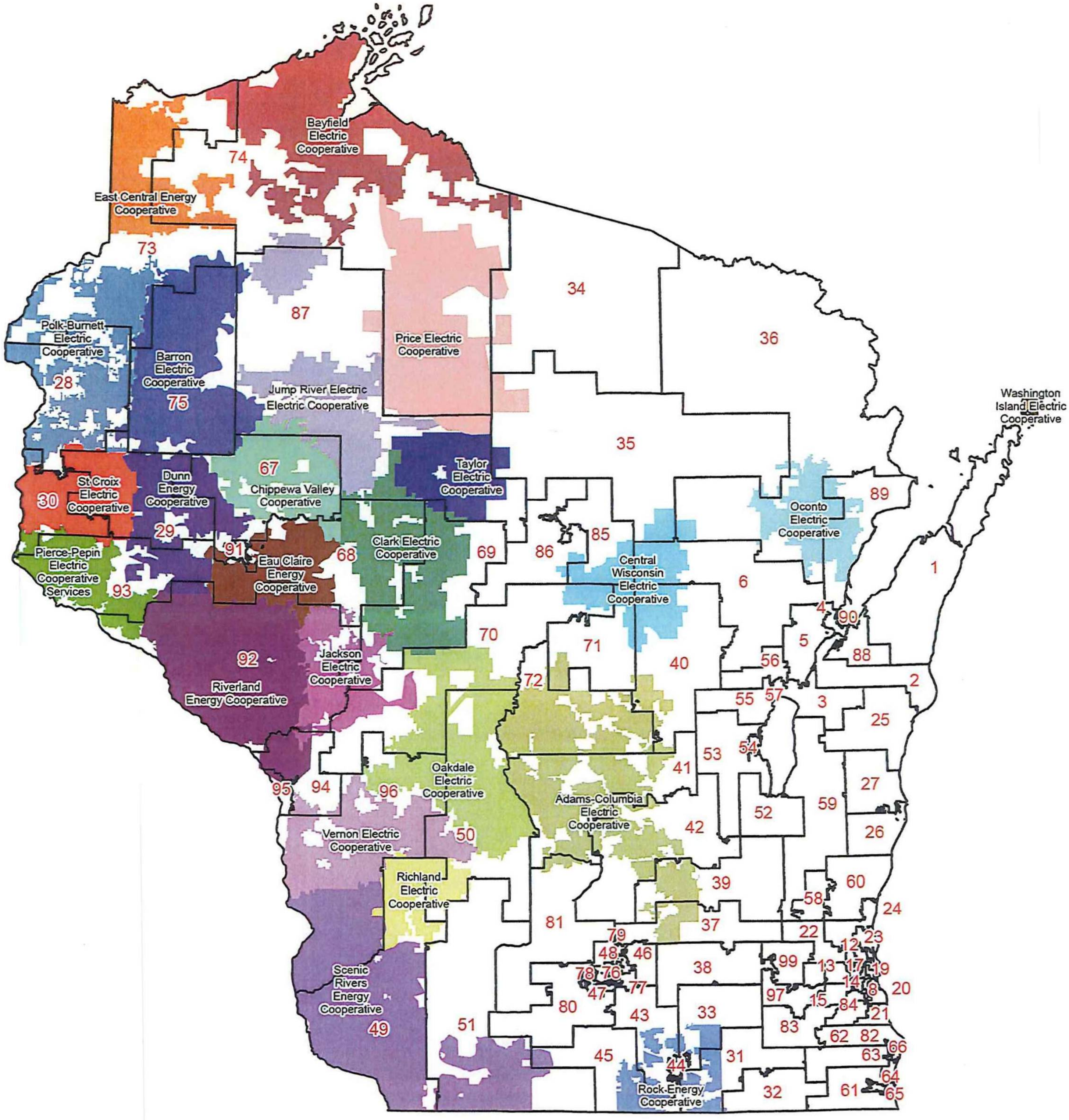
Chairman Steffen and Members of the Assembly Energy and Utilities Committee I certainly appreciate your time today and your efforts to grow and strengthen the energy infrastructure of our great State. Let's work cooperatively to ensure fairness to the rural members across Wisconsin. I oppose AB470 in its current form and hope that a solution can be found to address the concerns I have stated today.

Respectfully,

Jesse Singerhouse

Jesse Singerhouse
General Manager
Dunn Energy Cooperative

Wisconsin
Electric Cooperatives & Assembly Districts



Adams-Columbia Electric Cooperative	Clark Electric Cooperative	Jump River Electric Cooperative	Price Electric Cooperative	St Croix Electric Cooperative
Barron Electric Cooperative	Dunn Energy Cooperative	Oakdale Electric Cooperative	Richland Electric Cooperative	Taylor Electric Cooperative
Bayfield Electric Cooperative	East Central Energy Cooperative	Oconto Electric Cooperative	Riverland Energy Cooperative	Vernon Electric Cooperative
Central Wisconsin Electric Cooperative	Eau Claire Energy Cooperative	Pierce-Pepin Electric Cooperative Services	Rock Energy Cooperative	Washington Island Electric Cooperative
Chippewa Valley Electric Cooperative	Jackson Electric Cooperative	Polk-Burnett Electric Cooperative	Scenic Rivers Energy Cooperative	

Service territory data was compiled from electric cooperatives across the state of Wisconsin.
Accuracy of data cannot be guaranteed by PSC.
Legislative boundaries provided by Legislative Technology Services Bureau.

PUBLIC SERVICE COMMISSION OF WISCONSIN - JUNE 2022

States that have adopted "Right of First Refusal" Legislation in MISO

MISO

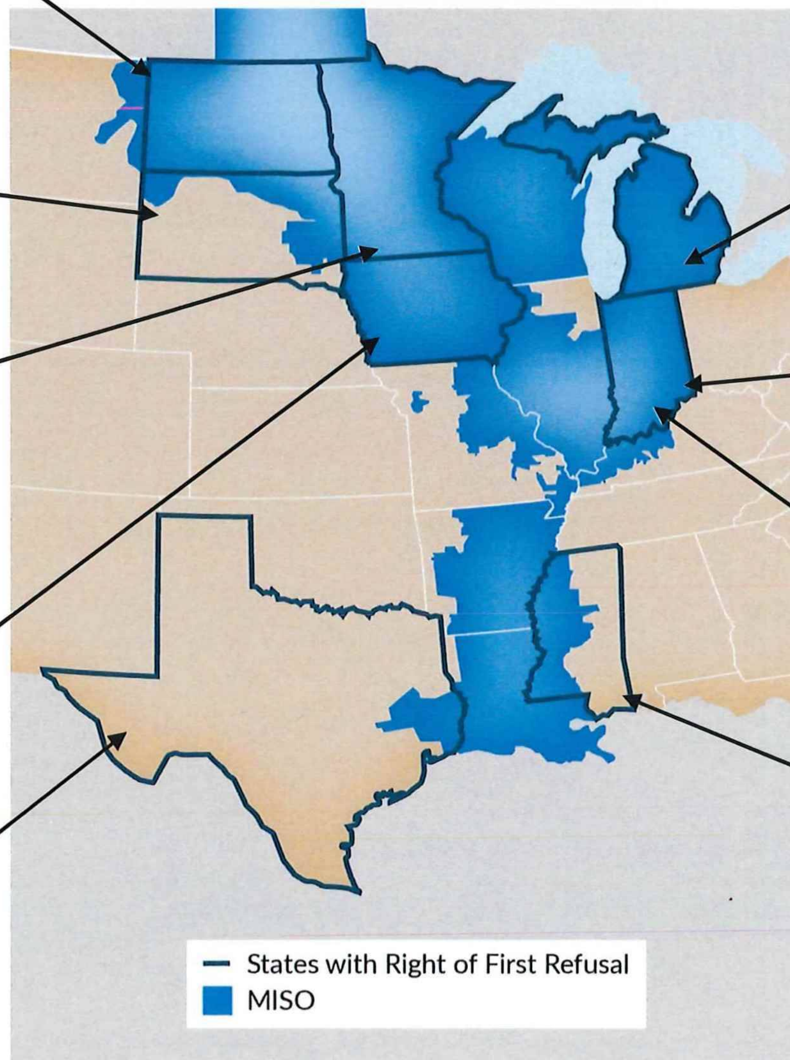
North Dakota
Passed Senate
47-0
Passed House
91-0
All GOP Control

South Dakota
Passed Senate
33-1
Passed House
66-0
All GOP Control

Minnesota
Passed Senate
65-0
Passed House
116-0
Democratic Governor
GOP control Legislature

Iowa
Passed Senate
30-17
Passed House
51-41
All GOP Control
Part of appropriation bill

Texas
Passed Senate
31-0
Passed House
141-5
All GOP Control



Michigan
Passed Senate
28-6
Passed House
71-29
Democratic Governor
GOP control Legislature

Indiana
Passed Senate
50-0
Passed House
77-16
All GOP Control

Indiana #2
Passed Senate
32-17
Passed House
59-39
All GOP Control

Mississippi
Passed Senate
50-1
Passed House
109-7
All GOP Control

Cost Savings Offered by Competition in Electric Transmission

Experience to Date and the Potential for Additional Customer Value

PREPARED FOR

LSP Transmission Holdings, LLC

PREPARED BY

Johannes P. Pfeifenberger

Judy Chang

Akarsh Sheilendranath

J. Michael Hagerty

Simon Levin

Wren Jiang

April 2019

THE Brattle GROUP

This report was prepared for LSP Transmission Holdings, LLC. It is based on the authors' analyses of publicly-available transmission data reported to FERC and in ISO/RTO transmission project tracking reports, as assembled for LSP Transmission Holdings, LLC, prior client engagements, and conference presentations. All results and any errors are the responsibility of the authors and do not represent the opinion of The Brattle Group or its clients.

Acknowledgement: We acknowledge the valuable contributions of many individuals to this report and to the underlying analysis, including LSP Transmission Holdings, LLC staff, and members of The Brattle Group for peer review. We would also like to acknowledge the very helpful feedback we have received from transmission developers, policymakers, regulators, and customer representatives in response to various presentations of the draft results of this study.

Table of Contents

List of Figures

Cost Savings Offered by Competition in Electric Transmission:

Evidence on Cost Savings to Date and the Potential for Additional Customer Value

Numerous studies have presented and discussed the high economic value that regional and interregional transmission investments can provide in the U.S.[1] Nevertheless, seven years after FERC Order No. 1000, major regional investments have been limited and interregional projects are almost non-existent. Advancing competition in transmission can help increase the value of the investments and provide more transparency into transmission costs. Doing so would ultimately increase the attractiveness of strengthening the regional and interregional transmission grid to create a more robust and cost-effective electricity system.

The current level of competition in electric transmission has been very limited. We have identified thirty-one competitive solicitations for transmission projects in ISO/RTO regions, of which 16 occurred in PJM and 10 in CAISO. Overall, the transmission projects subject to competition represent 3% of U.S. nationwide transmission investments between 2013 and 2017. The 3% includes all of the projects that have been selected through competitive solicitations, including projects proposed by incumbent utilities. The limited number of competitive projects is explained by restrictive regional planning criteria that have precluded most transmission investments from being subject to competitive processes. Some of these criteria are set out in Order 1000, limiting competitive processes to regionally cost-allocated transmission projects and excluding local projects.

Based on the experience with competitive projects in the U.S. to date, we estimate that the potential cost savings from expanding competitive processes could range from approximately 20% to 30%, consistent with savings achieved with similar competitive transmission processes in Canada, the U.K., and Brazil. At an estimated cost savings of 25%, the potential customer value from expanding competitive processes from 3% to 33% of all planned U.S. transmission investments would be approximately $8 billion over the course of five years. In addition to cost savings, competitive processes for transmission investments stimulate innovation through

1 For a summary of various studies see Pfeifenberger and Chang, *Well-Planned Electric Transmission Saves Customer Costs*, June 2016, pp. 5-14. Available at: https://wiresgroup.com/docs/reports/WIRES%20Brattle%20Report_TransmissionPlanning_June2016.pdf

opportunities for transmission developers to propose: (1) innovative technological and engineering solutions to more cost-effectively address identified transmission needs; and (2) cost containment mechanisms that reduce the extent to which customers are exposed to the risk of cost escalations.

We recommend that federal and state policymakers consider the positive experiences with competitive processes to date and expand the scope of competitive transmission investments to capture more of the innovation and cost reductions benefits achieved through competition. Applying more innovative and cost-effective solutions to both competitively- and traditionally-developed transmission projects will support the role that the transmission grid will play in ensuring system reliability, spurring economic development, and integrating renewable generation as the costs of generation and storage technologies continue to decline and the economy transitions to a clean-energy future.

Ultimately, the U.S. will require a more robust transmission infrastructure. Using competitive forces to stimulate innovation and reduce the costs of necessary investments both increases opportunities for transmission developers while providing value to customers.

Growth in U.S. Transmission Investments Have Primarily Been Reliability-Based and Locally-Developed Projects

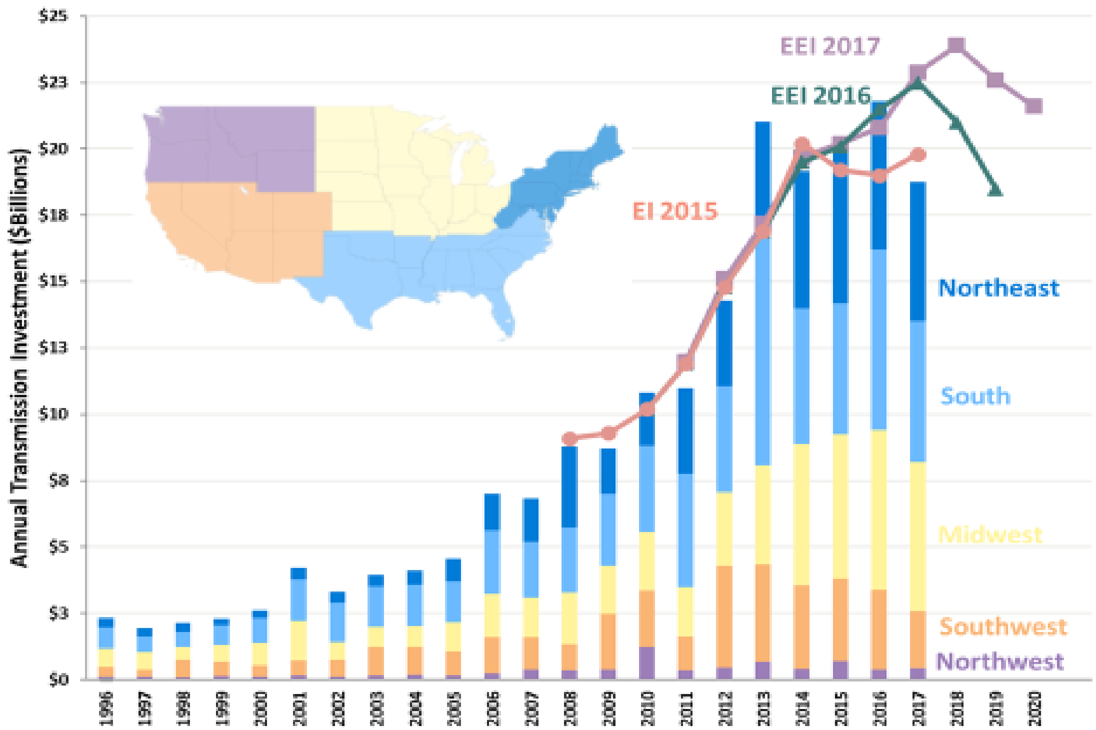
Investments in electric transmission facilities have grown significantly over the past 15 years in the U.S. As Figure 1 below shows, U.S. transmission companies are now investing approximately $20 billion/year in transmission infrastructure.

This growth was largely in response to a growing need to meet reliability standards, to cost-effectively integrate new generating resources, and to reinforce and replace the aging existing transmission infrastructure—much of which was developed 50–60 years ago during a period of rapid economic expansion and electricity demand growth in the 1960s and 1970s. Regulatory and governmental agencies, such as the Federal Energy Regulatory Commission (FERC) and the U.S. Department of Energy (DOE), have long documented this need to reinforce, replace, and modernize the nation's aging, inefficient, and heavily-congested transmission infrastructure as critical to meeting the future energy needs of the economy.[2]

---

[2] See, for example, U.S. DOE's QER Report: Energy, Transmission, Storage and Distribution Infrastructure, April 2015, p. S-5.

Figure 1
U.S. Annual Transmission Investments
(For FERC-jurisdictional and ERCOT Transmission Owners)



Sources and Notes: Regional Investment based on FERC Form 1 investment compiled in ABB Inc.'s Velocity Suite, except for ERCOT for years 2010–2017, which are based on ERCOT Transmission Project Information Tracking (TPIT) reports. Based on EIA data available through 2003, FERC-jurisdictional transmission owners estimated to account for 80% of transmission assets in the Eastern interconnection and 60% in WECC. Facilities >300kV are estimated to account for 60–80% of shown investments. EEI annual transmission expenditures updated December 2017 shown (2011–2020) based on prior year's actual investment through 2016 and planned investments thereafter.

Overall, every region has experienced growth in transmission investments to meet the various needs of the U.S. electricity industry. The transmission investments within markets operated by U.S. ISOs and RTOs accounted for over 80% of recent transmission investments by FERC-jurisdictional and ERCOT transmission owners.[3] From 2013 through 2017, an average of $17 billion/year of transmission investments were made within the U.S. ISO/RTO regions,

[3] In 2017, transmission investment within markets operated by U.S. ISO/RTOs was $15.5 billion, compared to $18.8 billion of total transmission investment made by FERC-jurisdictional and ERCOT transmission owners. The 2013–2017 average transmission investment made within U.S. ISO/RTOs was $17.2 billion/year, which compares to $20.1 billion/year average investment made by all FERC-jurisdictional and ERCOT transmission owners during the same period.

Transmission investments outside FERC jurisdiction and ERCOT (*e.g.*, those of public power agencies such as the Tennessee Power Authority, Bonneville Power Authority, or Western Area Power Authority) are not reflected in these transmission investment statistics.

including ERCOT.[4] Since 1999, transmission investments have grown the most within the ISO/RTO regions, ranging from 10% to 16% of average annual growth, compared to 6% to 10% in regions not operated by ISOs or RTOs.[5] Significant investments have been made, but relatively little has been built to meet the broader regional and interregional economic and public policy needs envisioned when FERC issued Order No. 1000. Instead, most of these transmission investments addressed reliability and local needs.

A Robust Transmission Grid Provides Benefits to Customers

The electricity industry is in the midst of major transitions due to significant changes in resource mix, environmental policies, electricity uses, and reliability and resiliency standards. While going through such transitions, the transmission grid continues to be the foundation that maintains reliability for all electricity users, integrates new generating resources, and improves the overall cost effectiveness of electricity service. The continued need for regional transmission investments that provide substantial reliability and economic benefits to all electricity users in the region is clear and continues to be better understood.[6]

Given the amount of transmission investments that are and will be needed across the country, we examine the possibility of advancing competitive processes in developing and constructing new transmission. This report analyzes the potential cost savings offered by competitive processes based on the experience to date and discusses how expanding those experiences could increase the benefits of having a robust transmission system to electricity users. To conduct our analysis, we undertook an extensive effort in collecting data and analyzed the costs of transmission projects to estimate the impacts of competitive processes across the U.S. We also reviewed international experiences with competitive transmission development in the Canadian provinces of Ontario and Alberta, the U.K., and Brazil.

---

4 Our analysis covers the years from 2013 to 2017, as explained in greater detail in the body of the report. Total transmission investment data for 2018 is not yet available.

5 In 1999, the seven US ISOs and RTOs invested only $1.6 billion on transmission assets, compared to $15.5 billion transmission investment in 2017. During the same period, transmission investments in the non-ISO/RTO regions grew from $0.7 billion in 1999 to $3.2 billion in 2017. See Figure 5 for more detailed data.

6 See, for example, Southwest Power Pool (SPP), *The Value of Transmission*, January 26, 2016, documenting that benefits of transmission investments have exceeded their costs by a ratio of 3.5-to-1. Accessed here: https://spp.org/documents/35297/the%20value%20of%20transmission%20report.pdf

Seven Years after Order No. 1000 Mandated Competition in Transmission Planning, 97% of U.S. Transmission Investments Occur Outside the Competitive Processes

In 2011, FERC Order No. 1000 sought to promote "more efficient or cost-effective transmission development" by requiring "opportunities for non-incumbent transmission developers to propose and develop regional transmission facilities through competitive transmission planning processes."[7] Despite the Commission's order and the efforts of FERC-jurisdictional regional transmission planning entities to modify their planning processes and tariff structure around cost allocation, only 3% of U.S. transmission investments approved between 2013 and 2017 have been subject to competitive processes that were open to non-incumbents.[8] The 2013-2017 share of competitive projects for individual regions range from none in ISO-NE[9] to 5.1% of total transmission investments in PJM, 6.8% in CAISO, and 7.0% in NYISO. FERC staff's recent assessment of transmission investment metrics shows that there is significant interest from and participation by many transmission developers in competing for the available opportunities.[10]

For the period from 2013 through 2017, competitively-developed projects account for about $540 million of average annual transmission investment, compared to the approximately $20 billion in average annual transmission investments made during the same period across the country.[11,12]

---

7 FERC, 2017 Transmission Metrics Staff Report, p. 6, October 6, 2017; also see FERC Order No. 1000: Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, Final Rule, July 21, 2011.

8 An estimated 3% of U.S. transmission investments approved through competitive processes is derived based on the value of competitive projects approved between 2013 and 2017, though recognizing that these approved competitive projects have not yet been placed in-service. See Figure 6 below for more details.

9 We recognize that several New England states have issued competitive solicitations for renewable and clean energy, which included proposed generation projects that were bundled with dedicated transmission projects.

10 FERC Staff, *2017 Transmission Metrics Staff Report*, October 6, 2017, p. 14, accessed here: https://www.ferc.gov/legal/staff-reports/2017/transmission-investment-metrics.pdf

11 See Section VI for the list of approved competitively-developed projects.

12 The $540 million per year average for 2013–2017 does not account for projects approved in 2018 and 2019, including MISO's $122 million Hartburg-Sabine Junction 500 kV transmission line (awarded late 2018), $50 million of projects approved by PJM in its 2018 competitive window, and NYISO's April 2019 approval of the AC Transmission Public Policy projects ($1.230 billion). If we include these projects, the 2013–2019 average is $587 million per year. Of the $20 billion/year of total U.S. transmission investments, $15 billion/year of the average annual transmission investments for 2013–

Transmission Project Eligibility Criteria for Competitive Processes are Restrictive, Reducing the Scope of Competition

The tariffs that specify the rules for transmission planning for each region currently exclude the large majority of transmission investments from competitive processes. We do not see compelling policy reasons for broad limits or having significant differences in criteria used in various regions that directly or indirectly exclude transmission projects from the competitive processes. In addition, limiting competition only to projects that are regionally cost allocated (as specified by FERC Order 1000) creates barriers to realizing the benefits of competition for those transmission projects whose costs are paid for solely by the local transmission users. By building on the full set of experience with competition from across regions, we recommend that federal and state policymakers consider expanding the scope of competitive transmission investments.

Subjecting more transmission investments to competition would stimulate innovation, increase the cost-effectiveness of the investments, and provide greater overall benefits to customers. For example, through its competitive process, MISO was able to increase the estimated benefit-to-cost ratio of its Hartburg-Sabine Junction project in Texas from 1.35 to 2.20.[13] At lower costs, transmission will more frequently provide cost effective solutions to the benefit of both customers and transmission developers. For the local transmission owners that must respond to cost pressures from regulators, applying innovations from competitive processes to reduce the costs of traditionally-developed projects also increases the companies' ability to invest in other valuable technologies to help meet customers' needs.

Significant Investments in Transmission Are Made Without Full ISO/RTO and Stakeholder Engagement in the Planning and Approval of Projects

Our analysis of the available transmission investment data for years 2013 to 2017 shows that about one-half of the approximately $70 billion of aggregate transmission investments by FERC-jurisdictional transmission owners in ISO/RTO regions are approved outside the regional planning

---

2017 were made within the six FERC-jurisdictional ISO/RTOs. Including ERCOT, which is not FERC jurisdictional, the estimated average annual transmission investments for ISO/RTOs is $17.2 billion/year.

13 MISO, Hartburg-Sabine Junction 500 kV Competitive Transmission Project, Selection Report, November 27, 2018, p. 2.

processes or with limited ISO/RTO and stakeholder engagement.[14] Instead, they are based solely on local planning processes of the existing transmission owners with only cursory reviews by the ISO/RTO planners.[15] Since locally-planned projects are not subject to competitive planning requirements under Order 1000, shifting transmission investment away from regional processes reduces the extent to which competitive processes can enhance the overall cost-effectiveness of transmission investments.

Figure 2 below summarizes for 2013–2017: (1) the estimated share of transmission investments placed in-service within various U.S. ISO/RTOs over a five-year historical period that were subject to the full ISO/RTO stakeholder-based regional transmission planning processes; and (2) the share of those investments that have been subject to competitive regional planning processes. As the figure shows, transmission investments not subject to the full regional planning process range from 29% in ISO-NE to 54% in PJM.

In our review of ISO/RTO transmission project cost estimation and cost tracking data, we found substantial differences in the amount of information available across regions. While some regions have implemented transparent project cost tracking mechanisms, some provide very limited cost information. Given that the great variance of project cost reporting and tracking standards makes it difficult to compare cost trends within and across the various planning regions, we recommend that FERC and the ISOs/RTOs consider implementing consistent minimum requirements for project cost reporting and tracking.

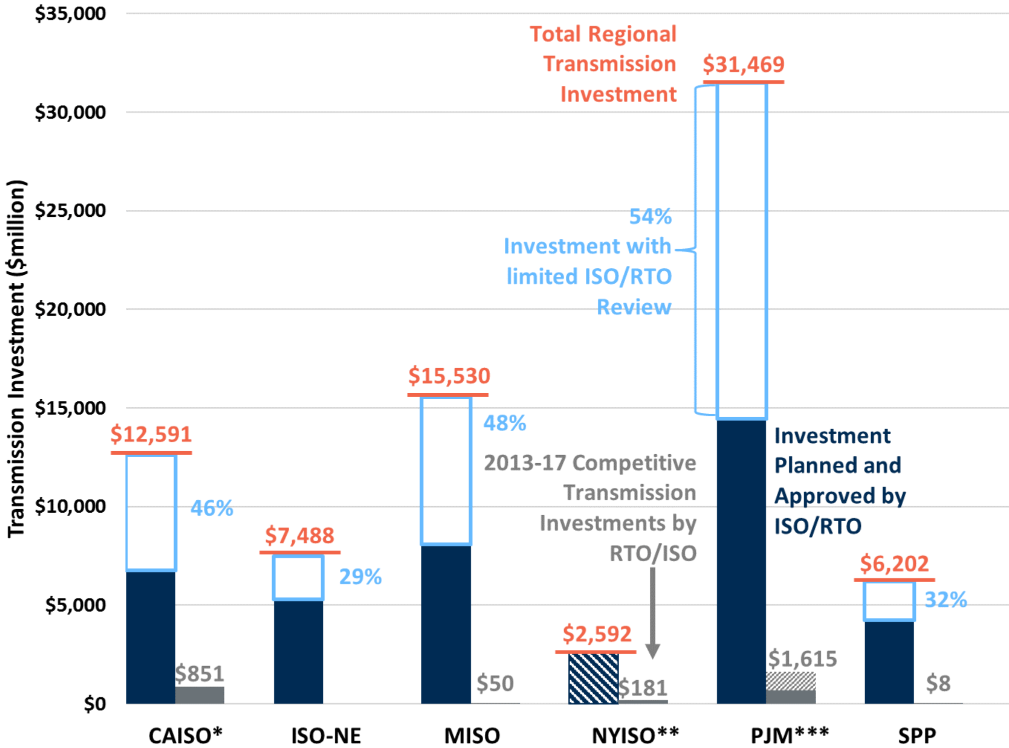
---

[14] The aggregate transmission investment of approximately $70 billion reflects the last 5 years of investments by transmission owners in FERC-jurisdictional ISO/RTOs (2013–2017), with the exception of CAISO (for which transmission investments reflected in the approximately $70 billion is for 2014–2016 only, due to data limitations).

[15] This issue has been central in a recent complaint by the California Public Utilities Commission before FERC. See FERC Order Denying Complaint (Docket No. EL17-45), August 31, 2018.

FERC, in response, issued an order denying the complaint and clarifying that transmission activities such as “maintenance, compliance, work on infrastructure at the end-of-useful life, and infrastructure security undertaken to maintain a transmission owner’s existing electric transmission system and meet its regulatory compliance requirements” are not considered transmission expansion activities and therefore are not subject to the regional transmission planning and expansion requirements of Order Nos. 890 and 1000. The order (still subject to request for rehearing) confirmed that ISO/RTOs are not required to maintain full oversight on transmission utilities’ activities not considered transmission system planning or expansion.

Figure 2
2013–2017 FERC-Jurisdictional Transmission Investments With Full and Limited Stakeholder Review within ISO/RTO Regional Planning Processes



Notes:

*CAISO Investment Planned and Approved by ISO percentage reflects data for 2014 through 2016. Percentages have been applied to total CAISO Transmission Investment over the 2013–2017 period. Data reflects transmission additions/approved investments of only PG&E, SCE, and SDG&E.

**NYISO investment reflects total investment throughout the market because data on Investment Planned and Approved by NYISO is not available. NYISO competitive transmission investment only accounts for the Western NY Public Policy project that was announced in 2017, but not the $1.230 billion AC Transmission Public Policy projects approved in April 2019.

***We have identified only three competitive PJM projects awarded to non-incumbent developers, totaling $663 million. PJM additionally awarded through its competitive solicitation windows 136 projects worth $952 million to incumbent transmission developers; few of these were open to non-incumbent participation because 132 of them involved upgrades to existing facilities. (Source: TEAC Project Statistics Presentation, available as part of the January 11, 2018 TEAC meeting materials; PJM presentation at WIRES Annual Meeting 2018)

SPP's values for 2013 and 2017 contain only partial December values, due to data limitations. Total Investment for each ISO/RTO reflects total FERC Form 1 transmission additions over the indicated time period. Investments approved by ISO/RTO exclude locally-planned projects and reflect the total value of transmission additions placed in-service over indicated time period, approved through ISO/RTO processes.

The Experience to Date Indicates that Competitively-Developed Transmission Offers Significant Innovation and Cost Savings for Customers

Of the competitively-developed transmission projects awarded to date, we were able to analyze sixteen transmission projects subject to competition in which cost data is available. On average across the sixteen projects, the selected proposals were priced significantly below the *initial* project cost estimates prepared by the ISO/RTOs or incumbent transmission owners prior to receiving proposals through the competitive process. The low costs of some of the proposals are consistent with the significant interest and participation in competitive processes by numerous market participants as documented by FERC staff.[16] In addition to the low costs, the selected project proposals generally have included cost caps or cost-control measures, which are expected to reduce the risks to ratepayers of cost escalations as the projects are developed and constructed in the coming years.

Since the competitively-developed projects are not yet constructed, we assume they will likely incur at least some level of cost escalations as they advance through the development and construction phases of the projects. We thus analyze a range of potential cost escalations for the competitively-developed projects: (1) projects completed as proposed with no escalation, (2) cost escalation equal to 5-years of inflation, and (3) cost escalation similar to historical average cost escalations for transmission projects.[17] Figure 3 below shows for two regions, CAISO and MISO, the estimated cost range of competitively–developed projects (dark green bars) under these three cost escalation assumptions compared to our estimate of the final costs of the same project if it had been traditionally developed (blue bar) and incurred typical historical escalations from the initial project cost estimates.[18]

If the projects subject to competition could be developed and constructed *without any cost increases*, the estimated *average cost savings could be as high as 28% in MISO and 50% in CAISO* relative to the likely costs of these projects if they had been traditionally developed. Actual cost savings are expected to be smaller given the potential for at least some level of cost escalations. We estimate that overall cost savings of 15% for MISO and 29% for CAISO would result from the competitive processes even if the competitively-developed projects were to experience percentage cost escalations similar to the historical experience with major transmission projects in these regions.

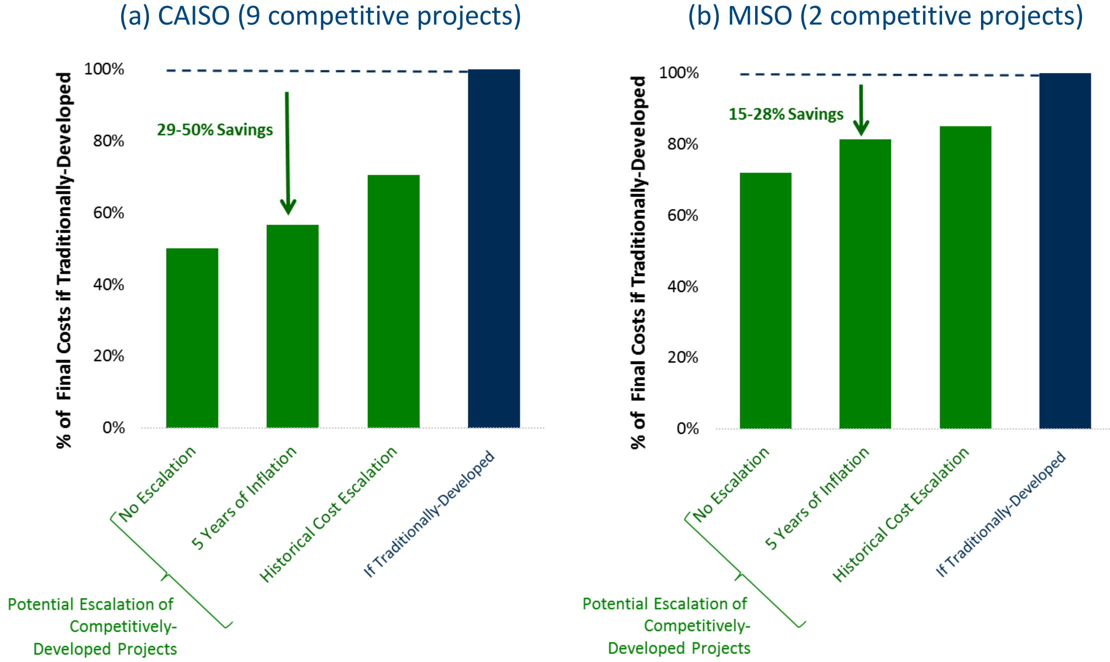
---

16 FERC, *2017 Transmission Metrics Staff Report*, October 6, 2017, p. 22. Available at: https://www.ferc.gov/legal/staff-reports/2017/transmission-investment-metrics.pdf

17 We estimate that, relative to initial estimates, the costs of major transmission projects historically escalated on average by 18% in MISO and by 41% in CAISO. See Appendix A for more details.

18 Only CAISO develops and publishes an initial cost estimate for all transmission projects, allowing for a more direct comparison of the costs of competitively-developed and traditionally-developed projects. Our estimate of potential customer savings for MISO relied on transmission owners' initial cost estimates for estimating average historical cost escalations for transmission projects. These cost escalations reflect factors such as inflation during the often lengthy project development process as well as costs associated with conditions imposed during the siting and permitting process.

Figure 3
Cost Savings for Competitive Projects in Selected RTO/ISOs



Notes: Cost comparisons are based on the actually-reported nominal dollars. Cost escalation in the "5 Year of Inflation" case assumed 2.5% inflation rate and in the "Historical Escalation" case is equal to the historical escalation of major regional transmission projects (41% for CAISO and 18% for MISO).
Source: See Figure 18 in Section IX below.

The range of potential savings in MISO and CAISO assuming some level of cost escalation is consistent with the estimated cost savings from competitive processes in other parts of North America—such as 22% savings in NYISO, 21% in Alberta, and 16% in Ontario—and the already realized cost savings in international markets, which include savings of 23% to 34% in the U.K. and about 25% in Brazil. Based on these experiences with competition to date, we estimate that competitive transmission development processes can be expected to yield cost savings ranging from 20% to 30% on average.

Based on our experience and discussion with industry participants, the cost savings reflected in the selected competitive proposals can be attributed to a wide range of innovative approaches to transmission development. They include innovative project designs, such as using new technologies for conductors, tower type, materials, and foundations; optimized routing to reduce permitting costs; innovative contracting; cost-control mechanisms (such as improved risk sharing with and incentives for the engineering and construction contractors); and innovative partnerships and financial structures, including public-private partnerships to streamline project permitting.

In regions with "solution-based" competitive procurement processes, such as NYISO and PJM, competition can foster significant additional benefits from innovative project design and risk mitigation to address the identified need. For example, in the solicitation process for PJM's Artificial Island Project, many developers proposed a wide range of solutions to meet the identified transmission need. Some developers also proposed innovative lower-voltage design options that addressed all the needs identified by PJM at substantially lower costs and reduced constructability risk. In contrast, other developers offered to include significantly longer circuit-miles and only 500 kV options at significantly higher costs. In NYISO, the solutions-based competitive processes similarly attracted multiple design innovations that yielded lower costs and higher customer benefits.

We see significant value in such "sponsorship" or "solutions-based" approaches to the competitive process because developers are also competing on broader design ideas, which can yield significant additional cost benefits when innovative solutions can more cost-effectively meet identified system needs. While we document significant cost savings for project-based competitive processes, the potential savings are likely to be less because developers are purchasing materials and services from the same market and must meet the project-specific criteria. Thus, to maximize the value of competitive transmission development processes, we recommend moving toward more sponsorship or solutions-based approaches.

The Cost of Competitive Processes

The cost of administering and participating in competitive processes are not trivial, but are relatively small compared to the costs of the transmission projects and the potential cost savings from developing and implementing the competitive processes. Administrative costs associated with the evaluation process are typically assigned to the project developers participating in the competitive processes.

For example, SPP's cost of administering its first competitive process was approximately $500,000—requiring the recovery of $47,000 from each of the eleven respondents and accounting for approximately 3% of the project's $17 million cost estimate, none of which was directly passed through to transmission customers.[19] During 2016 and 2017, PJM spent $1.7 million administering

---

[19] SPP estimated that developers spent $300,000 to $400,000 to prepare each of the 11 proposals submitted to SPP's solicitation for the North Liberal–Walkemeyer 115 kV project, for a total of $3.3 million to $4.4 million of developer costs. (See *Prepared Statement of Paul Suskie, Executive Vice President and*

five solicitation windows, 97% of which were recovered from the project proponents through fees.[20] The U.K. regulator Ofgem estimated that approximately 4% of large competitive transmission projects' total costs are associated with conducting and participating in the competitive bidding process—with developer costs estimated at 2% of total project cost, the cost of conducting the solicitation at 1%, and the rest incurred by the network owners and system operators.[21]

Developers' costs (including the ISO/RTO administrative charges imposed on them) will ultimately have to be recovered and would thus need to be reflected in the costs of competitively-developed proposals—even if not every developer includes these costs in every proposal and every round of competitive solicitations. As a result, these costs likely are included in competitive project costs and thus already accounted for in the above estimates of cost savings. For individual developers who have gained experience in the processes, we anticipate that their costs will decrease over time as they improve and streamline assembling a competitive proposal. The lessons learned from each process will carry forward and improve the industry's ability to explore innovative techniques in developing transmission projects.

Expanding the Scope of Competitive Processes Could Yield Significant Cost Savings

Increasing the share of transmission investments developed through competitive transmission planning processes is likely to yield significant customer savings. Based on the experience with competitively-developed transmission in the U.S. and other countries, competitive processes are more likely to be adopted for higher voltage and higher cost projects. Of all the recent RTO-planned transmission investment in PJM and MISO (excluding supplemental and transmission owner-initiated projects), about half of all MISO-planned projects and 77% of PJM-planned projects cost more than $25 million.[22] Based on voltage, about half of the investments planned by MISO and PJM have involved voltage levels above 300kV and about 66% have been above 150kV.

General Counsel, Southwest Power Pool, Inc., FERC Docket No. AD16-18-000.) Similar to SPP's costs of administering the competitive solicitation process, these costs are incurred by project developers and will thus tend to be reflected in the proposed project costs.

20 PJM, Competitive Planning Process Proposal Fee Status Update, December 14, 2017, p. 4.

21 Ofgem, *Extending Competition in Electricity Transmission: Impact Assessment*, May 27, 2016, Sections 3 and 4.7.

22 See Figure 20 for more details.

Based on these statistics, and recognizing that a substantial portion of transmission development cannot be open to competition because it involves refurbishment or upgrades to aging existing facilities, it should be possible to expand the scope of competition to cover approximately one quarter to one third of total transmission investments—particularly if the current barriers to the development of cost-effective regional and interregional transmission projects to address market efficiency and public policy needs can be reduced. If competition can reduce costs by 25% on average, the cost savings from competition on one third of the planned U.S. transmission investments would be approximately $8 billion over five years. Figure 4 below shows that these potential cost savings to customers range from a five-year total of $4.4 billion at the low end (if only 25% of U.S.-wide investment was subjected to competition and competitively-developed projects yielded 20% cost savings) to $9.0 billion at the high end (if 33% of total transmission investments were developed competitively and achieved 30% cost savings).

Figure 4
Potential 5-Year Cost Savings from Increasing U.S. Transmission Investments Subject to Competition

Estimated Savings from Competitive Processes (*% of Transmission Costs*)	**20 - 30%**
Estimated 5-year US-wide Transmission Investment (*$ million*)	$100,000
Current Share of Competitive Projects (*% of Total Investment*)	3%
Estimated 5-Year Cost Savings of Expanded Competitive Processes ($ million)	
25% of Transmission Investment Subject to Competition	$4,400 - $6,600
33% of Transmission Investment Subject to Competition	$6,000 - $9,000

To conclude, the experience with competitive transmission processes to date demonstrates that they can attract significant interest from a wide range of transmission developers and have been able to deliver significant innovations and cost savings. Expanding these competitive processes to a larger portion of total transmission investments would magnify the net benefits of the investments and meaningfully reduce customer costs. Developing a larger portion of transmission projects through competitive processes would also benefit transmission owners by reducing rate pressure and increasing the attractiveness of transmission investments as a solution to the challenges of a rapidly-changing energy economy.

I. About this Report

LSP Transmission Holdings, LLC ("LS Power") asked The Brattle Group to undertake an in-depth examination of the experience with competitive transmission. The objective of this report includes assembling available data on the costs of transmission projects in the U.S. and abroad. As a part of this undertaking, we set out to evaluate current experience with competition and discuss whether increasing the scope of competitive transmission in the U.S. would offer meaningful cost savings. In this report, we:

1. Analyze the extent to which transmission investments are fully vetted through stakeholder-driven ISO/RTO planning processes;
2. Examine the use of competitive processes in ISO/RTO transmission planning and solicitation to date;
3. Review the evidence from existing competitive processes in the U.S. and Canada;
4. Assess whether and if so, the extent to which competitively-developed projects are likely to result in cost savings compared to traditionally-developed transmission;
5. Estimate the potential customer benefits that would be achieved by expanding the scope of competition; and
6. Provide selected case studies of U.S. and international experiences with competitive processes.

We have presented a draft summary this analysis at several public forums[23] and obtained valuable feedback from transmission developers, policymakers, regulators, and customer representatives, which we have incorporated in this report. We describe our updated analyses, approach, and findings in this report, with additional detail presented in the Appendices.

II. Historical Transmission Investments in the U.S.

We have previously explained that much of today's transmission grid was built in the 1960s and 1970s, with very limited transmission investments occurring from the mid-1980s through the late 1990s.[24] U.S. investments in electric transmission facilities have grown from approximately

---

23 For example, see 2018 presentations to NARUC and WIRES.

24 For example, see J.P. Pfeifenberger, J. Chang, and J. Tsoukalis, *Investment Trends and Fundamentals in U.S. Transmission and Electricity Infrastructure*, Presented to the JP Morgan Investor Conference,

$2 billion per year during the late 1990s to approximately $20 billion per year during the last five years. Transmission investments made within regions operated by FERC-jurisdictional U.S. ISO/RTOs and ERCOT account for over 80% (about $17 billion/year) of this recent level of transmission investments. Figure 5 below provides details of these transmission investment levels for 1999 and the period from 2010 through 2017.

To assemble the investment amount, we relied on FERC Form 1 reports for all U.S. transmission owners reporting to FERC and computed total annual investments in "Electric Transmission Plant-in-Service" for each company and each year over the past two decades. We also relied on the Department of Energy's Form EIA-861, which provides information on transmission owners' ISO/RTO affiliations—thereby allowing us to analyze annual transmission investments for each ISO/RTO and non-ISO/RTO region.[25]

July 17, 2015, slide 6, posted at: http://files.brattle.com/files/5916_investment_trends_and_fundamentals_in_us_transmission_and_electricity_infrastructure.pdf

25 Each year, FERC-jurisdictional transmission owners (*e.g.*, electric utilities) file FERC Form 1 reports, which collect financial and operational data from each filing entity. We analyzed these FERC Form 1 reports for all reporting U.S. transmission owners and computed total annual investments in "Electric Transmission Plant-in-Service" for each company and each year over the past two decades. For 2010–2017, our analysis reflects actual annual ISO/RTO affiliations for the FERC-jurisdictional utility. However, since Form EIA-861 includes ISO/RTO membership information only since 2010, our classification of transmission investments prior to 2010 is based on 2010 ISO/RTO membership information. This has the advantage that the significant changes in ISO/RTO members during the first decade of ISO/RTO formation do not distort the investment trends within the specific geographic regions. For non-ISO/RTO utilities analyzed in our study, we identified the utility's NERC region and evaluated investments at the regional stratification. Finally, for ERCOT—a system operator that is not a FERC jurisdictional ISO or RTO—we relied on ERCOT's Transmission Project and Information Tracking (TPIT) reports to document transmission investments within ERCOT. While some transmission owners operating in ERCOT file FERC Form 1 reports, relying on ERCOT's TPIT provides a more comprehensive record of transmission investments.

Figure 5
U.S. Annual Transmission Investments (2010–2017)
(nominal $ billion)

	1999	2010	2011	2012	2013	2014	2015	2016	2017	2013–2017 Total	1999–2017 CAGR
CAISO	$0.33	$1.7	$0.9	$3.5	$3.2	$2.6	$2.5	$2.4	$1.8	**$12.6**	**10%**
ISO-NE	$0.09	$0.7	$0.6	$1.4	$1.8	$1.4	$1.7	$1.4	$1.2	**$7.5**	**15%**
MISO	$0.34	$1.4	$1.0	$1.3	$2.5	$2.7	$3.0	$4.0	$3.3	**$15.5**	**14%**
NYISO	$0.08	$0.5	$0.7	$0.3	$0.4	$0.5	$0.5	$0.5	$0.6	**$2.6**	**12%**
PJM	$0.46	$1.9	$3.4	$2.9	$4.1	$6.6	$7.3	$7.1	$6.4	**$31.5**	**16%**
SPP	$0.11	$0.8	$0.6	$1.2	$1.0	$2.1	$0.9	$1.4	$0.9	**$6.2**	**12%**
FERC-jurisdictional ISO/RTOs	**$1.43**	**$7.0**	**$7.3**	**$10.6**	**$12.9**	**$15.9**	**$15.8**	**$16.9**	**$14.4**	**$75.9**	**14%**
ERCOT	$0.14	$0.8	$1.2	$1.0	$5.3	$0.9	$0.9	$2.0	$1.1	**$10.2**	**12%**
U.S. ISO/RTOs	**$1.56**	**$7.8**	**$8.4**	**$11.7**	**$18.2**	**$16.8**	**$16.8**	**$18.9**	**$15.5**	**$86.1**	**14%**
Other WECC	$0.32	$1.7	$0.7	$0.8	$1.2	$0.8	$1.3	$1.0	$0.9	**$5.2**	**6%**
Southeast & Other	$0.43	$1.3	$1.8	$1.8	$1.6	$1.6	$1.9	$1.9	$2.3	**$9.4**	**10%**
Total Reported to FERC	**$2.31**	**$10.8**	**$11.0**	**$14.3**	**$21.0**	**$19.1**	**$19.9**	**$21.8**	**$18.8**	**$100.7**	**12%**

Source: The supporting data for Figures 1 and 7 show annual transmission investments made by U.S. utilities since the 1990s (see Appendix C).

While the increased investments in transmission provide significant reliability and economic benefits in excess of project costs,[26] the scale of the current level of investments understandably can raise concerns over their impacts on customer costs and the extent to which the investments are being made in a cost-effective manner. The increasing share of transmission costs in retail rates increases the scrutiny by customer groups and state regulators and for that reason we are sensitive to the need to ensure that future investments are made in the most cost-effective manner by increasing transparency in transmission planning, and in the approval and cost-tracking processes

---

26 For example, see Southwest Power Pool, *The Value of Transmission*, January 26, 2016, which finds that SPP's transmission investments provide benefits that significantly exceed costs with a benefit-to-cost ratio of approximately 3.5-to-1. Accessed here: https://spp.org/documents/35297/the%20value%20of%20transmission%20report.pdf

See also Midcontinent ISO (2014), MTEP14 MVP Triennial Review: A 2014 Review of the Public Policy, Economic, and Qualitative Benefits of the Multi-Value Project Portfolio, September 2014, finding benefit-to-cost ratios of transmission investments ranging from 2.6-to-1 to 3.9-to-1. Accessed here: https://www.misoenergy.org/Library/Repository/Study/Candidate%20MVP%20Analysis/MTEP14%20MVP%20Triennial%20Review%20Report.pdf as discussed later in this report.[27] Efforts such as competitive processes that can unlock greater cost-effectiveness in transmission infrastructure development will have the potential to provide significant additional benefits to customers. Allowing cost savings to be recognized will require a robust and consistent cost tracking approach across the country.

III. U.S. Experience with Competitive Transmission Processes

The Federal Energy Regulatory Commission issued its final rule on Order 1000, creating incentives for regional and interregional planning, and encouraging competition in transmission planning, on July 21, 2011. In Order 1000, the Commission stated that it was "amending the transmission planning and cost allocation requirements established in Order No. 890 to ensure that Commission-jurisdictional services are provided at just and reasonable rates and on a basis that is just and reasonable and not unduly discriminatory or preferential."[28] One of the main objectives of Order No. 1000 was to increase regional and interregional transmission development. Well-planned regional and interregional transmission projects are needed to facilitate the growth of renewable generation, capture load and generation diversity across larger footprints, reduce transmission congestion, and improve system reliability and resiliency. However, now, seven years after the Commission's Order No. 1000 was issued, much of the transmission development is focused on reliability and local needs, with only a modest increase in regional projects, and no progress in developing interregional projects, to address market efficiency and public policy needs.

Order No. 1000 also sought to promote "more efficient or cost-effective transmission development" by way of increased competition.[29] To achieve that goal, the order set in place rules requiring "opportunities for non-incumbent transmission developers to propose and develop regional transmission facilities through competitive transmission planning processes."[30] FERC staff's 2017 assessment of transmission investment metrics shows that there is significant transmission

---

27 The share of transmission costs in retail rates grew from 6% in 2008 to 10% in 2017 based on EEI data.

28 FERC Order No. 1000: Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities; Docket No. RM10-23-000; Issued July 21, 2011.

29 2017 Transmission Metrics Staff Report, p. 6, October 6, 2017; see also FERC Order No. 1000: Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, Final Rule, July 21, 2011.

30 SPP, 2017 Transmission Metrics Staff Report, p. 6, October 6, 2017; see also FERC Order No. 1000: Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, Final Rule, July 21, 2011.

developer interest in competing for transmission investment opportunities.[31] However, the strong interest by transmission developers has not translated into significant competitive opportunities. Between 2013 and 2017, only an estimated 3% of the total U.S. transmission investments have been subject to competitive processes.[32] In some regions, such as SPP and MISO, less than 1% of total 2013–2017 transmission investments were subject to the competitive procurement processes established by these ISO/RTOs. In other regions, such as PJM, CAISO and NYISO, shares of competitive projects have been comparatively larger, but still range from only 5.1% to 7.0% of total transmission investments from 2013 to 2017. In ISO-NE and non-RTO regions none of the region's transmission investments have been subject to the regional planning entities' competitive transmission processes to date.[33]

Figure 6 below shows estimated annual investments for competitively-planned transmission by selection year from 2013 through 2017. The 2013–2017 average of annual competitive transmission investments of $540 million/year remains relatively small compared to $20 billion/year average of annual transmission investments in the U.S.[34]

---

31 FERC Staff, *2017 Transmission Metrics Staff Report*, October 6, 2017, p. 14,

32 As shown in Figure 6, we estimated the amount of competition relative to total investment by comparing the amount of projects selected in 2013 to 2017 to the total investment that occurred in those years. While FERC required compliance with the Order 1000 within 18-months of issuance of order, examining the share of competitive projects during 2013–2017 implicitly allows for a two-year implementation window. For more details see also: https://www.ferc.gov/industries/electric/indus-act/trans-plan.asp

33 We note, however, that some of the New England states' competitive generation solicitations have been bundled with transmission projects. This occurred outside the regional transmission planning processes.

34 The $540 million per year average for 2013–2017 does not account for projects approved in 2018 and 2019, including MISO's Hartburg-Sabine Junction 500 kV transmission line ($122 million), $50 million of projects approved by PJM in its 2018 competitive window, and NYISO's 2019 approval of the AC Transmission Public Policy projects ($1,230 million).

Figure 6
Competitively-Developed Projects in FERC-Jurisdictional Regions and Selection Years 2013-2017
(Project costs in nominal $ million)

	CAISO	ISO-NE	MISO	NYISO	PJM*	SPP	Non-RTO	Total
2013	$144	$0	$0	$0	$0	$0	$0	$144
2014	$148	$0	$0	$0	$90	$0	$0	$238
2015	$425	$0	$0	$0	$912	$0	$0	$1,337
2016	$133	$0	$50	$0	$471	$8	$0	$662
2017	$0	$0	$0	$181	$142	$0	$0	$323
Total Estimated Competitive Project Costs Selected in 2013-2017	**$851**	**$0**	**$50**	**$181**	**$1,615***	**$8**	**$0**	**$2,705**
Total Reported FERC Form 1 Transmission Investment in 2013-2017	$12,600	$7,500	$15,500	$2,600	$31,500	$6,200	$14,600	$90,500
Total Estimated Competitive Project Costs Selected in 2013-2017 (% of 2013-2017 Total Investment)	**6.8%**	**0.0%**	**0.3%**	**7.0%**	**5.1%***	**0.1%**	**0.0%**	**3.0%**

Notes: In addition to these regions, ERCOT accounts for another $10.2 billion of transmission investments for 2013–17.
* In estimating the total costs of competitive projects approved in PJM, we include 136 projects awarded under competitive windows to incumbent transmission owner with total costs of $952 million, of which 132 projects are upgrades to existing facilities that were not open to competitors.

IV. State of Competition in U.S. Transmission Planning

To examine why competition in transmission planning has remained limited to only 3% of investments, we reviewed the FERC-jurisdictional ISO/RTOs' tariffs and business process manuals and compiled the key eligibility criteria and types of exclusions that limit the scope of competitive processes. We find that the criteria and exclusions vary considerably across ISO/RTOs as summarized in Figure 7 below. This review of the various competitive transmission processes highlights that five of six FERC-jurisdictional ISO/RTOs allow competitive transmission planning to various degrees for three major types of transmission projects or needs: (1) Reliability Projects, (2) Economic or Market Efficiency Projects, and (3) Public Policy Projects.

Figure 7
Competitive Transmission Project Eligibility for U.S. ISO/RTOs

	CAISO	ISO-NE	MISO	NYISO	PJM	SPP
Types of Projects Eligible for Competition	Reliability, Economic, Public Policy	Reliability, Economic, Public Policy	Market Efficiency, Multi-Value (MVP)	Reliability, Economic, Public Policy	Reliability, Economic, Public Policy	ITP, High Priority, Interregional
Exclusions						
Exclusions for Reliability Projects		✓ (Based on Need Date)	✓*		✓ (Based on Need Date)	✓ (Based on Need Date)
Exclusions for Local Cost Allocated Projects (per Order 1000)	✓	✓	✓	✓	✓	✓
Exclusion of Upgrades (per Order 1000)	✓	✓	✓	✓	✓	✓
Exclusions Based on Voltage						
Voltage > 300 kV						
Voltage 200-300 kV			✓** *(For MEP)*			
Voltage 100-200 kV	✓		✓** *(For MEP)*		✓***	
Voltage < 100 kV	✓	✓	✓**		✓***	✓

Notes: Additionally, competitive transmission may be precluded in certain states, due to state Right of First Refusal (ROFR) provisions.
*In MISO, projects that are only classified as Baseline Reliability Projects are locally allocated (regardless of voltage), making them ineligible for competitive processes. Projects designated as Baseline Reliability Projects and MEPs/MVPs are cost-allocated as though they are MEPs/MVPs.
**MISO limits competition to MEPs and MVPs; MEPs must have a total cost of at least $5 million and a minimum voltage of 230 kV; MVPs must have a total cost of at least $20 million and a minimum voltage of 100 kV; see MISO Tariff Attachment FF, Sections II.B, and II.C.
***PJM has exceptions to these exclusions on lower voltage facilities for specific types of reliability violations. These exceptions are detailed in PJM Manual 14F Section 5.3.4.

As shown in the figure above, in some cases, certain transmission projects may not be eligible for competitive processes if their operating voltages are below a defined voltage level. As also as shown in the figure, applying the competitive processes only to regionally-planned transmission projects, consistent with Order No. 1000, the ISO/RTOs exclude from competitive processes all projects needed for "local" reliability or that rely strictly on local cost recovery. This rule has an unintended consequence. For example, MISO only applies its competitive process to multi-value projects that are above $20 million and 100 kV and market efficiency projects that are above $5 million and 345 kV. This is because reliability projects in MISO's footprint are effectively not candidates for the competitive process as their costs are now allocated to the local zones instead of allocated through a regional sharing mechanism. This change in cost allocation has greatly limited the scope of

MISO's competitive process given that reliability projects account for the overwhelming majority of MISO-planned and approved transmission investments.

In addition, Order 1000 does not affect state or local laws or regulations regarding the construction of transmission facilities, including authority over siting or permitting of transmission facilities, and in some cases those laws may work (and, in fact, may have recently been modified) to exclude some projects from competition. The Final Rule issued by the Commission in Order 1000 emphasized that the reforms did not eliminate incumbent transmission owner's right of first refusal (under federally-approved tariffs) for upgrades to its own existing facilities.[35] This means that any upgrades to existing facilities are currently excluded from competitive processes. While excluding upgrades to existing facilities is consistent with Order 1000, a vague or overly broad application of this clause (or favoring upgrades over potentially more valuable alternative transmission investments) nonetheless limits the region from realizing additional cost-efficiencies through competitive development of transmission.

CAISO and NYISO impose fewer restrictions on the eligibility criteria for transmission projects to enter into the competitive processes, while MISO is the most-restrictive overall. Proportionally, CAISO and NYISO have made a significantly higher share of total transmission investments available to competitive solicitations than the other FERC-jurisdictional planning regions. However, even within the more permissive CAISO and NYISO competitive processes, there are important differences. For example, in New York, the competitive process for the "AC Transmission Public Policy Project" provided for the possibility of non-incumbent developers' utilizing existing utility rights-of-way, thereby enabling broader participation in the process.

The collective experience across these regions shows that competitive processes are feasible for a wide variety of transmission projects, even though certain types of projects may currently be excluded from competitive processes in other regions. For example, given that NYISO and CAISO have successfully implemented competitive transmission planning processes with fewer restrictions, there is not a compelling reason for other ISO/RTOs to apply more restrictive processes than NYISO or CAISO.

In some developers' views, subjecting regionally-planned projects to competition has discouraged transmission companies from suggesting potentially valuable regional projects, anticipating that the projects would need to go through competitive processes and thus could be delayed. Such

---

35 See FERC Order No. 1000, par. 319.

concerns are legitimate. However, as competitive processes become more common and well-practiced, they should run more smoothly and require less time.

We recommend that the more restrictive processes be reviewed by stakeholders and policymakers and potentially modify the criteria to expand the set of qualifying projects based on the positive experiences in other regions. Taking this step would increase the cost-effectiveness of transmission investments and provide greater benefits to customers. We recognize, however, that doing so may require modifying the requirements of Order 1000, which currently only requires competitive processes for new transmission projects with region-wide cost sharing. This limitation to regional cost-sharing already had unanticipated consequences as shown by MISO eliminating regional cost sharing for the reliability projects (regardless of voltage or investment level), thus effectively eliminating reliability projects from its competitive planning requirements.[36] Opportunities for taking actions that could result in the expansion of transmission projects that can participate in competitive processes exist at both the federal level (including through ISO/RTO stakeholder processes and FERC proceedings) and the state level (to the extent existing state laws serve as an impediment to competition for new transmission investments).

V. Scope of Transmission Investment Oversight

Long-standing FERC policy requires regional oversight of transmission investment in ISO/RTO regions. In Order 2000, FERC declared that each RTO "should have the ultimate responsibility for both transmission planning and expansion within its region."[37] FERC explained that "[t]he rationale for this requirement is that a single entity must coordinate these actions to ensure a least cost outcome that maintains or improves existing reliability levels." To gain greater insights into the scope of full ISO/RTO and stakeholder engagement in the planning and approving of U.S. transmission investments within their regions, we analyzed ISO/RTO-reported transmission investment data over 2013 through 2017. From the limited available databases and reports, we identified all transmission projects that have been placed into service and computed the aggregate annual investments using the ISO/RTO-reported final project costs (excluding financing costs during construction). This aggregate annual transmission investment reflects all transmission

---

36 Midcontinent Indep. Sys. Operator, FERC Docket ER13-186-000, at PP 3–5 (Oct. 25, 2010) (Order No. 1000 Compliance Filing). See also Midcontinent Indep. Sys. Operator, 142 FERC ¶ 61,215 (2013); both Commissioners Clark and Moeller dissented.

37 FERC Order No. 2000 at p. 486 (slip).

projects that were planned and reviewed fully through the ISO/RTO transmission planning processes. We then compared these ISO/RTO-approved investments to the total transmission plant-in-service additions data for each region as reported in FERC Form 1. This comparison yields an estimate of the share of a region's total transmission investments by FERC-jurisdictional transmission owners that were made with full ISO/RTO and stakeholder engagement during the planning process.[38]

The remainder of the regions' transmission investment is planned by the local transmission owners without full engagement of the relevant ISOs/RTOs and stakeholders. While these investments will be reviewed by the ISO/RTOs to avoid conflicts with regional reliability objectives and added to their planning models, the need for these local projects is generally determined by the local transmission owners and not through coordinated regional planning efforts leading to reduced oversight.[39]

As documented in more detail in Appendix C to this report, our review of ISO/RTO-approved transmission investments relied on annual reports and various data published as part of the ISO/RTOs' transmission planning processes. For CAISO, due to the unavailability of the requisite publicly-reported data, we relied on information obtained from filings in a recent CPUC complaint to the FERC related to transmission spending of PG&E, SDG&E, and SCE utilities.[40] For the other FERC-jurisdictional ISO/RTO regions, we relied on the "Transmission Expansion Plan In-Service" project lists of MISO, quarterly-updated data from "Cost Allocation and Construction Cost" databases of PJM, "Regional System Plan Transmission Cost Tracking Reports" of ISO-NE, and

---

[38] We recognize that this estimate may somewhat understate the share of transmission investments subject to full ISO/RTO review because the total transmission investment data reported in FERC Form 1 includes AFUDC while the RTO-reported project cost data may not.

[39] See FERC Order Denying Complaint (Docket No. EL17-45), August 31, 2018.

As noted earlier, FERC, in response to a formal complaint of California Public Utilities Commission *et al.*, issued an order denying the complaint and clarifying that transmission activities such as "maintenance, compliance, work on infrastructure at the end-of-useful life, and infrastructure security undertaken to maintain a transmission owner's existing electric transmission system and meet its regulatory compliance requirements" are not considered transmission expansion activities and therefore are not subject to the transmission planning and expansion requirements of Order Nos. 890 and 1000. The order confirmed that ISO/RTOs are not required to maintain full oversight on transmission utilities' activities not considered transmission system planning or expansion.

[40] Formal Complaint of California Public Utilities Commission, *et al.* (Docket No. EL17-45).

"Transmission Expansion Plan" reports of SPP.[41] Our analysis was not able to cover NYISO, which does not publish cost information on approved projects. We excluded ERCOT due to similar data limitations and its non-FERC-jurisdictional status.[42]

Our analysis of the available transmission investment data for those five years for FERC-jurisdictional ISO/RTOs show that roughly one-half of the approximately $70 billion of total ISO/RTO transmission investments by FERC-jurisdictional transmission owners have been made without full ISO/RTO and stakeholder engagement during the planning process. This finding indicates that about one-half of FERC-jurisdictional transmission investments are made based on local planning processes with only limited ISO/RTO review and stakeholder input, limiting the scope of regional planning under Order 2000 and effective regional coordination of transmission planning to identify least-cost solutions that meet the identified needs. Limited stakeholder engagement leads to a lack of transparency in properly assessing the relative costs and benefits of various transmission projects being developed by transmission owners, and may not entail developing the most effective and cost-efficient transmission solutions for identified needs. To control costs of transmission development, having greater review of the transmission projects would be useful. Acknowledging that adding ISO/RTO and stakeholder review could slow down certain projects' development timeline, we recommend that, at minimum, the ISOs/RTOs should have detailed project tracking mechanism that consistently document project cost estimates at various stages of the project, particularly when the project needs are first identified and at the completion of the projects.

Figure 8 below summarizes the estimated shares of transmission investments placed in-service within various U.S. ISO/RTO regions over the 2013-2017 period. This figure includes projects that were subject to the ISO/RTOs' full stakeholder-based transmission planning and approval processes. As the figure shows, the share of transmission investments subject to the full ISO/RTO regional planning processes ranges from 71% in ISO-NE to 46% in PJM. Across the five ISO/RTO regions for which data is publicly available, approximately 53% of all transmission investments within the regions are subject to the full ISO/RTO regional planning processes and therefore,

---

41 See sources in Appendix C.

42 Given that ERCOT is not a FERC-jurisdictional ISO, not all ERCOT participants file FERC Form 1 reports and our sources for transmission investment within ERCOT come solely from ERCOT. We are unable to analyze the extent to which local transmission owners invest in transmission that is not subject to ERCOT planning and reporting. We attempted to examine the Monthly Construction Progress Reports that ERCOT filed with the Texas Public Utility Commission (PUC), but in 2008 the PUC stopped publishing EXCEL format summaries of these reports.

almost half (47%) of all transmission investments in these ISO/RTO regions are not subject to the full ISO/RTO planning process and associated stakeholder review.

Figure 8
Transmission Additions Subject to Full ISO/RTO Planning Processes

Region	Years Reviewed	FERC Jurisdictional Additions by Transmission Owners (nominal $million) *(based on FERC Form 1 Filings)*	Investments Approved Through Full ISO/RTO Planning Process (nominal $million)	% of Total FERC Jurisdictional Investments Approved Through Full ISO/RTO Planning Process	% of Total FERC Jurisdictional Investments With Limited ISO/RTO Review
CAISO*	2014–2016	$7,528	$4,043	54%	46%
ISO-NE	2013–2017	$7,488	$5,300	71%	29%
MISO	2013–2017	$15,530	$8,068	52%	48%
NYISO	2013–2017	$2,592	n/a	n/a	n/a
PJM	2013–2017	$31,469	$14,458	46%	54%
SPP	2013–2017	$6,202	$4,226	68%	32%
Total		**$70,810**	**$36,095**	**53%**	**47%**

Notes: % of Total FERC-jurisdictional transmission investment approved through full ISO/RTO planning process is calculated as share of total investments by FERC-jurisdictional transmission owners in each region.
*CAISO data only reflects transmission additions/approved investments of PG&E, SCE, and SDG&E.
See Appendix C for detailed sources and notes.

The introduction of competitive processes coincides with substantial increases in locally-planned transmission that are outside the full regional planning processes. As an example, in PJM, the value of regionally-planned "baseline" projects significantly exceeded the value of locally-planned "supplemental" projects prior to the 2014 introduction of competitive windows. Since 2014, however, the value of supplemental projects has increased substantially and now significantly exceeds that of regional baseline projects.[43] Coinciding with this decline in PJM's share of regionally-planned baseline projects, the share of baseline projects eligible to participate in PJM's competitive processes has declined as well. For example, the value of projects eligible for competition has declined from $912 million and $471 million in 2015 and 2016 to $142 million and $50 million in 2017 and 2018. At the same time, the value of projects *not* eligible for competition increased from $1,140 million and $290 million in 2015 and 2016 to $3,092 million and $2,020 million in 2017 and 2018.[44]

---

43 PJM, TEAC Project Statistics, January 10, 2019, slide 6. Available at: https://www.pjm.com/-/media/committees-groups/committees/teac/20190110/20190110-project-statistics-2018.ashx

44 *Id.*, slide 16.

In addition to finding that significant shares of the overall transmission investments are not currently subject to full regional planning processes, we faced significant difficulties in accessing cost information on approved projects. The scope of publicly-available ISO/RTO cost tracking and reporting information varies significantly across the regions even for the projects that are subject to the full ISO/RTO planning process. While not all databases are always updated, MISO and SPP currently maintain a transparent cost recording and tracking processes for projects approved thorough their regional planning processes. The transmission project cost reporting and tracking information available for the other ISO/RTO areas is more limited.

For transmission projects planned by the local transmission owners that are *not* subject to full ISO/RTO regional planning review, we are unable to find a centralized place that tracks the costs of these transmission projects. For example, while PJM administers multiple cost-tracking databases, those databases do not provide updated cost information on investments made by transmission owners outside the full PJM regional planning process (*i.e.*, the "Supplemental and TO-Initiated Projects" in PJM). These projects are not developed with active engagement of PJM or its stakeholders, and a lack of cost tracking and reporting makes it difficult to assess whether these investments are being made in a cost-effective manner. In the case of NYISO and CAISO, we find that there are no standardized, regularly-updated public-reporting processes to track and report current and final project costs even for the ISO-approved transmission projects.

Given that the great variance of project cost reporting and tracking standards make it difficult to compare cost trends within and across the various ISO/RTO areas, we recommend that FERC and the ISOs/RTOs consider implementing consistent minimum requirements for project cost reporting and tracking.

VI. North American Competitively-Developed Transmission Projects

Since 2013 (two years after Order 1000 was implemented), FERC-jurisdictional ISO/RTOs have completed 31 competitive transmission procurement processes, as summarized in Figure 9 below: sixteen by PJM, ten by CAISO, two by MISO and NYISO, and one by SPP.[45] CAISO, MISO, and SPP have employed bid- or project-based competitive processes in which transmission developers submit proposal for an ISO/RTO-defined project scope. In contrast, NYISO and PJM employ sponsor- or solutions-based competitive processes in which transmission developers "sponsor"

45 PJM's Artificial Island and several of the early CAISO competitively-developed projects were not subject to Order 1000.

specific project configurations as solutions to address ISO/RTO-identified transmission needs. We discuss experience in non-ISO/RTO regions in Section XI.

Figure 9
Experience with Competition in FERC-Jurisdictional ISO/RTO Regions Since 2013

ISO/RTO	Processes Completed	Process Type	Awards
CAISO	10	Projects	10
MISO	2	Projects	2
SPP	1	Projects	1
PJM	16	Solutions	139
NYISO	2	Solutions	3
ISO-NE	0	Solutions	0
All Regions	**31**		**155**

Even within the limited set of projects subject to competition, transmission developers have shown significant interest across ISO/RTO regions. Over the 2013–2017 period, PJM received 794 project proposals in 16 competitive solicitation windows, with non-incumbent transmission developers submitting 46% of these proposals.[46] PJM approved 139 projects, 132 of which were upgrades to existing facilities that excluded non-incumbent participation.[47]

We briefly reviewed the experience with competitive transmission in ERCOT. While ERCOT is not a FERC-jurisdictional system operator and thus not subject to FERC Order 1000, it has had experience with competition in transmission investments when the Texas State Legislature mandated that the Public Utility Commission of Texas (PUCT) develop the Competitive Renewable Energy Zones (CREZ) transmission projects. The PUCT conducted a competitive selection process but did not require cost-based proposals. The PUCT simply designated both incumbent transmission owners and non-incumbent transmission developers to construct different portions of the CREZ transmission system. No other competitive processes have been used in ERCOT since the development of the CREZ projects.

46 PJM's 2018 Window 1 has resulted in the award of one project to Dominion with a cost of less than $1 million, which was approved by the PJM Board in February 2019. See: PJM, Regional Transmission Expansion Plan 2018, February 28, 2019, p. 27. Available at: https://www.pjm.com/-/media/library/reports-notices/2018-rtep/2018-rtep-book-1.ashx?la=en

47 See PJM's presentation at WIRES Annual Meeting 2018: http://wiresgroup.com/docs/WIRES%20Meeting%20Materials/2018%20WIRES%20Annual%20Mtg_Craig%20Glazer.pdf

Figure 10 below includes a list of competitive projects across the U.S. and Canada and shows the selected developer for each of them.

Figure 10
North American Competitive Transmission Projects Summary

ISO/RTO	Project	Year of Decision	Selected Developer	Award to Incumbent?
CAISO	Gates-Gregg project (subsequently cancelled)	2013	PG&E/MidAmerican w/ Citizen Energy	Yes
CAISO	Imperial Valley Project	2013	Imperial Irrigation District	No*
CAISO	Sycamore-Peñasquitos 230 kV	2014	SDG&E w/ Citizen Energy	Yes
CAISO	Delaney-Colorado River Project	2015	DCR Transmission	No
CAISO	Estrella Substation Project	2015	NextEra	No
CAISO	Wheeler Ridge Junction Project	2015	PG&E	Yes
CAISO	Suncrest Project	2015	NextEra	No
CAISO	Spring Substation	2015	PG&E	Yes
CAISO	Harry Allen-Eldorado Project	2016	Desert Link	No
CAISO	Miguel Substation	2014	SDG&E	Yes
MISO	Duff-Coleman 345 kV	2016	LS Power w/ Big Rivers	No
MISO	Hartburg-Sabine Junction 500 kV	2018	NextEra	No
NYISO	Western NY Public Policy Transmission	2017	NextEra	No
NYISO	AC Transmission Public Policy Segment A	2019	North America Transmission and NYPA	No
NYISO	AC Transmission Public Policy Segment B	2019	Niagara Mohawk and New York Transco	Yes
PJM	Artificial Island Project	2015	LS Power	No
PJM	Thorofare Project	2015	Transource	No**
PJM	AP South Market Efficiency Project	2016	Transource w/ BGE and Allegheny Power	No**
PJM	136 Projects Awarded to Incumbents (132 Upgrades)	2014-2017	Various	Yes
SPP	North Liberal – Walkemeyer 115 kV (subsequently cancelled)	2016	Mid Kansas Electric	Yes
AESO	Fort McMurray West 500 kV	2014	Alberta PowerLine Limited Partnership	Yes
IESO	East West Tie Line	2013	NextBridge Infrastructure	No
IESO	Wataynikaneyap Power Project	2015	Fortis Inc.	No

Notes:
* While Imperial Irrigation District (the selected developer of the Imperial Valley project) is the incumbent in the Imperial Valley Region, it is not a CAISO PTO and thus not an incumbent within the CAISO footprint.
** Transource is a joint venture between AEP and Great Plains Energy.

To conduct an analysis of the potential cost impact to customers, we first analyzed the cost of the selected proposals relative to either the respective ISO/RTO's initial cost estimate (MISO, SPP, CAISO,[48] Alberta, and Ontario), or the difference between selected proposals and the lowest cost proposal from incumbents (PJM and NYISO).[49] The differences in competitively-developed project proposals relative to these reference cost levels are summarized for MISO, SPP, CAISO, PJM, NYISO, Alberta, and Ontario in Figure 11 through Figure 15.

As detailed in Appendix A, we compare the final project costs to initial cost estimates for completed major regional transmission projects. In addition, in Section XII, we briefly summarize the experience with competition for transmission projects in the United Kingdom (U.K.) and Brazil.

As shown in the analyses documented in Figure 11 through Figure 15, competitive project costs generally are significantly below the respective reference cost levels. These cost differences are quite significant. In MISO and SPP, for example, competitively-developed projects have been proposed between 15% and 50% below the ISO/RTOs' initial project cost estimates.

In solutions-based bidding processes, where there are not prior cost estimates for the specific project proposals, we compare the selected proposal's costs to the cost of the lowest-cost proposal from the incumbent transmission owner. Certainly these are not exactly the same reference points because they could be completely different transmission projects solving the same problem, but they provide a sense of how the incumbent transmission owners approached the identified transmission needs. For example, the experience with PJM's Artificial Island Project shows that the cost of PJM's selected solution is 60% below the lowest-cost incumbent solution initially submitted. In NYISO, the winning proposal was 22% below the lowest-cost proposal by an incumbent transmission owners.[50] Overall, we observe that competitively-developed transmission projects have been proposed at a cost that, on average, has been about 40% below these reference cost levels.

---

48 CAISO provides a range for the cost estimate of both competitively-developed and traditionally-developed projects. Figure 12 shows those estimates for competitive projects. A comparison of CAISO and transmission owner cost estimates for traditionally-developed projects shows that the transmission owner estimates are generally consistent with the high end of the CAISO range. See Table 23 in Appendix A and Table 18 in Appendix C.

49 The PJM and NYISO sponsorship models do not lend themselves to the development of an initial ISO/RTO cost estimate as they do not develop their own solutions. We thus compare the cost of the winning bid to the incumbent transmission developer's lowest-cost bid. The Artificial Island project is the only one we analyzed in PJM due to the lack of availability of cost data for the other projects.

50 In addition to this cost advantage, the winning proposal offered higher NYISO customer benefits than the lowest-cost incumbent proposal, as shown in Table 13 of Appendix C.

As shown in Figure 11 through Figure 15, these competitive proposals have in many cases included cost caps and other cost control measures, which to varying degrees will reduce, though not necessarily fully eliminate cost escalation risks during the course of the projects' development life. For example, while the $103.9 million proposal for MISO's Hartburg-Sabine Junction project was 15% below MISO's estimated project costs (in 2018 dollars), the cost guarantee for the project is set at $114.8 million for the completed project (in future dollars, to include the impact of inflation during the development process).[51] In SPP, many of the proposals in the competitive process for the North Liberal–Walkemeyer 115 kV project included cost caps, even though the SPP-selected project did not have one. Similarly, Alberta's Fort McMurray project was estimated at CAD$1.43 billion or 21% below the AESO's own estimate, but the cost of the winning proposal has since increased to CAD$1.61 billion due to allowances for changes in routing (but which likely would have equally affected the AESO estimate).[52]

Figure 11
MISO and SPP Competitive Projects Summary

ISO/RTO	Project	Year of Decision	ISO Cost Estimate	Selected Proposal ($million)	Selected Proposal vs. ISO Cost Estimate	Cost Containment Offered
MISO	Duff-Coleman 345 kV	2016	$59	$50	-15%	Yes
MISO	Hartburg-Sabine Junction 500 kV	2018	$122	$104	-15%	Yes
SPP	North Liberal–Walkemeyer 115 kV (subsequently cancelled)	2016	$17	$8	-50%	No*

Notes: *While SPP's selected project did not have cost-containment, six of 11 proposals did have some form of cost containment. Within SPP's evaluation methodology, cost containment is one of several potential approaches to reducing project risk that can add up to 50 points (out of a total of 1,000 possible points) to a project's score.
Source: MISO Data from selection reports dated December 2016 (for Duff-Coleman 345kV Project) and November 2018 (for Hartburg-Sabine Junction Project). SPP Data from Recommendation Report dated April 12, 2016.

---

51 MISO, Hartburg-Sabine Junction 500 kV Competitive Transmission Project, Selection Report, November 27, 2018, p. 5.

52 See Fort McMurray West 500 kV Transmission Project, available here: https://www.aeso.ca/grid/competitive-process/fort-mcmurray-west-500-kv-transmission-project/ (also noting that the submitted proposal included all project-related costs while the AESO estimate only included construction costs)
See also AUC Decision 21030-D02-2017, p. 122, available here: http://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2017/21030-D02-2017.pdf

Figure 12
CAISO Competitive Projects Summary

Project	Year of Decision	CAISO Cost Estimate*	Selected Proposal ($million)	Selected Proposal vs. CAISO's Estimate*	Cost Containment Offered
Gates-Gregg (subsequently cancelled)	2013	$115–$145	$130	-10% to +13%	No
Imperial Valley	2013	$25	$14	-43%	Yes
Sycamore-Peñasquitos 230kV	2014	$111–$221	$108	-51% to -2%	No
Delaney-Colorado River	2015	$300	$280	-7%	Yes
Estrella Substation Project	2015	$35–$45	$20	-56% to -43%	Yes
Wheeler Ridge Junction	2015	$90–$140	$60	-57% to -33%	No
Suncrest	2015	$50–$75	$37	-50% to -25%	Yes
Spring Substation	2015	$35–$45	$28	-38% to -20%	No
Harry Allen-Eldorado Project	2016	$144	$133	-8%	Yes
Miguel	2014	$30–$40	n/a	n/a	n/a

Notes:
*As shown, CAISO reports a high-low range for many project cost estimates. Because we observe that cost estimates prepared by the local transmission owners for traditionally-developed projects tend to be close to the CAISO's high end of its cost estimates, the high end of the percentage cost difference shown in column 5 above will be more representative for assessing the cost savings from competitive processes.
For Sycamore-Peñasquitos 230kV Transmission Line Project, competitive solicitation originally selected an overhead design but was subsequently changed to an underground design after project was awarded to winning proposal.
Year of Decision, and Cost Containment Offered based on CAISO selection reports, with the exception of the Miguel project. Miguel's selection year and winner per CAISO market notice. Also note that while Imperial Irrigation District (winner of the Imperial Valley project) is an incumbent, it is not a participant (i.e., non-PTO) within CAISO.
CAISO Cost Estimate Range from Estimates reported in selection reports and CAISO functional specification documents.
Winning proposal estimates for Gates-Gregg, Estrella Substation Project, and Suncrest from Approved Project Sponsor Agreements; for Imperial Valley and Harry Allen-Eldorado Project from CAISO selection reports; for Wheeler Ridge Junction and Spring Substation from PG&E's response to data request CPUC-PGE-053 in FERC Docket No. ER16-2320-002; for Sycamore-Peñasquitos 230kV Transmission Line Project from its Approved Project Sponsor Agreement and its CPUC Certificate of Public Convenience and Necessity decision filing; for Delaney-Colorado River Project from its CPUC Certificate of Public Convenience and Necessity application.

Figure 13
Selected PJM Competitive Projects Summary

Project	Year of Decision	Selected Developer(s)	Lowest-Cost Proposal from Incumbent ($million)	Updated Project Cost ($million) (Current Estimate)	Updated Project Cost vs. Incumbent Proposal	Cost Containment Offered
Artificial Island Project	2015	LS Power	$692	$280	-60%	Yes
AP South Market Efficiency	2016	Transource w/ BGE and Allegheny Power	n/a	$328	n/a	No
Thorofare Project	2015	Transource	n/a	$72	n/a	No
136 Incumbent Projects (132 upgrades)	2014-2017	Various	n/a	$952	n/a	n/a

Notes on PJM's Artificial Island Project: Initially, PSEG proposed 14 (of the 26) solutions for Artificial Island, with costs ranging from a low of $692 million to a high of $1.5 billion. Of the 26 proposed projects, only two satisfied the performance criteria specified, so according to the selection white paper "PJM undertook additional engineering review to identify the most effective solution to stated needs, taking into consideration the elements of submitted proposals." PSEG ultimately provided a proposal with an estimated project cost of $277–$285 million, with $221 million in cost containment for specific work. However, this proposed project came only after PJM had analyzed the most effective components of the 26 initial proposals and applied its findings to the existing proposals. Finally, it should be noted that LS Power's winning proposal contains $146 million cost containment for their portion of the project. Adding incumbent substation work to LS Power's competitive portion increases the total cost of the solution to the $263 million to $283 million range. LS Power's cost containment contained fewer exceptions than PSEG's cost containment, which led to the recommendation of LS Power's project. Current comprehensive E&C cost for the PJM's Artificial Island Project awarded to LS Power, including work on incumbent developer's facilities is reported at $280 million.

Figure 14
NYISO Competitive Project Summary

Project	Year of Decision	Selected Developer	Lowest-Cost Proposal from Incumbent ($million)	Selected Proposal Cost Estimate (2017 $million)	Selected Proposal vs. Incumbent Proposal	Cost Containment Offered
Western NY Public Policy Transmission	2017	NextEra	$232	$181	-22%	No
AC Transmission Public Policy Segment A	2019	North America Transmission and NYPA	n/a	$750	n/a	n/a
AC Transmission Public Policy Segment B	2019	Niagara Mohawk and New York Transco	n/a	$479	n/a	n/a

Sources: NYISO, Western New York Public Policy Planning Report, October 17, 2017; NYISO, AC Transmission Public Policy Transmission Plan Report, April 8, 2019.

Figure 15
Alberta (AESO) and Ontario (IESO) Competitive Projects Summary

ISO/RTO	Project	Year of Decision	Initial ISO Cost Estimate	Initial Estimate of Selected Proposal	Updated Estimate of Selected Proposal	Updated Estimate of Selected Proposal vs. Initial Estimate	Cost Containment Offered
AESO	Fort McMurray West 500 kV	2014	$1,800	$1,430	$1,614*	−21%*	Yes
IESO	East West Tie Line	2013	$928	$439	$777	−16%	No

Notes on McMurray West 500 KV Transmission Project:
Initial Cost Estimation is AESO Planning estimate +/− 50% (CAD million) for construction costs only.
Winning Proposal is in 2019 CAD million and includes all project costs. Update reflects current estimate in 2020 CAD million
* For AESO, the updated estimate of winning proposal is shown for information only. The initial cost advantage (*i.e.*, the 21% cost advantage of the winning proposal vs. Initial AESO estimate) is calculated using the initial estimate of winning proposal cost vs. Initial AESO estimate. The updated cost of the winning proposal shown reflects costs associated with finalizing of the project route, which was not finalized at the time of Project award and was not reflected in the AESO's Initial Estimate. Therefore, for cost comparison purposes, it is assumed that the Initial AESO estimate would change similar to the change in the selected proposal cost to reflect the finalized route.
Notes on East West Tie Line:
Initial Cost Estimation is incumbent proposal with comparable design as winning proposal in 2020 CAD million.
Winning proposal is in 2012 CAD million. Updated Cost Estimate reflects current estimate in 2020 CAD million.

VII. Case Study: MISO's Experience with Competitive Projects

While competitive processes can significantly reduce customer costs based on the relatively low costs of the selected proposals, the benefits go beyond cost savings. The results of MISO's first two competitive solicitations show competition produced advanced project due diligence, risk reduction, and increased cost certainty for customers by the time that the selection process is complete. Thus, the competitive process effectively facilitated careful risk assessment and mitigation upfront, allowing the ISO/RTO to gain visibility into how developers arrange for the best plans for project engineering, siting, and construction, thereby providing a more robust project cost estimate that the developers are willing to uphold.

MISO conducted two competitive processes since 2016 and both were successful in attracting significant interest from transmission developers. The developers identified lower-cost solutions and proposed approaches to reducing the impact of possible cost escalations on transmission customers. For example, in discussing the results of its first competitive solicitation, the Duff-Coleman 345 kV project in Indiana and Kentucky, MISO highlighted the "dedication, innovative thinking, and competitive spirit" of the respondents that will "benefit MISO, its members, and ultimately all consumers of electricity in helping us build a stronger and more reliable electric grid for today and tomorrow."[53] In reviewing the results of its second competitive solicitation, the Hartburg-Sabine Junction project in east Texas, MISO was further encouraged to find that there was a significant improvement in the quality of proposals between the first and second solicitations, stating that "it was clear RFP Respondents that participated in the Duff-Coleman solicitation brought forward meaningful insights and experience they gained in that process."[54] The additional experience of developers can be seen in the results. Whereas only one project scored above 80 (on a 100 scale) in the first solicitation for Duff-Coleman, five proposals did so in MISO's second solicitation for Hartburg-Sabine Junction.

Figure 16 below summarizes the two solicitations that MISO completed. In both cases, MISO received over 10 proposals and selected a developer with estimated construction costs 15% below MISO's initial project cost estimate.

In MISO's detailed reports on its selection processes, MISO highlighted the most noteworthy results of the procurement processes and many of the innovative features proposed by the developers. In the competitive process for the Duff-Coleman project, MISO noted that all of the proposals came in lower than MISO's initial cost estimate and developers provided a range of cost caps, concessions, and commitments, including caps on construction costs. MISO noted that bidders made substantial efforts in preparing their proposals for pre-construction surveys and research and had gone to great lengths to understand the complexity of the regulatory and permitting frameworks, including early consultations with regulatory authorities.

The selected proposal for the Duff-Coleman 345 kV project was awarded to Republic Transmission (an LS Power Subsidiary), which MISO found to have the "highest degree of certainty and specificity, the lowest risk, and low cost."[55] MISO also found the selected project proponent's design to be superior to other proposals while remaining competitive on cost. MISO valued the rigor and specificity throughout the proposal, including a robust documentation of all

---

53 MISO, Duff-Coleman EHV 345 kV Competitive Transmission Project, Selection Report, December 20, 2016, p. 2. Available at: https://cdn.misoenergy.org/Duff-Coleman%20EHV%20345kv%20Selection%20Report82339.pdf

54 MISO, Hartburg-Sabine Junction 500 kV Competitive Transmission Project, Selection Report, November 27, 2018, p. 3.

55 MISO, Duff-Coleman EHV 345 kV Competitive Transmission Project, Selection Report, December 20, 2016, p. 3.

implementation "sub-criteria," which reduces the risks of cost and schedule overruns. MISO similarly found the selected developer's O&M plan to be "comprehensive and highly specific."[56]

Figure 16
MISO Competitive Transmission Solicitations

	Duff-Coleman EHV 345 kV Project	Hartburg-Sabine Junction 500 kV Project
Project Scope	One 345 kV line	One 500 kV line, four 230 kV lines, and a 500 kV substation
Project Location	Southern Indiana and Western Kentucky	Eastern Texas
Selection Year	2016	2018
Number of Proposals	11	12
Noteworthy Elements of Proposals	- Caps on implementation costs, ROE, and capital structure - Early regulatory consultations - Pre-construction surveys	- Schedule guarantees - 10 or 40 year ATRR caps, ROE caps - Diverse designs proposed - Significant preliminary fieldwork
Proposal Selected	Republic Transmission, LLC (LS Power Subsidiary)	NextEra Energy Transmission Midwest, LLC
Features of Winning Proposal	- Superior design - Most complete proposal - Robust cost caps - Low O&M costs - Most long-term certainty	- Robust design at low cost - Cost certainty (construction cost cap and 10-year ATRR caps) - Enhanced flexibility - Extensive planning and outreach - Hurricane-related experience
Construction Cost Estimates	MISO = $58.9 million Winning Proposal = $49.8 million Difference = -$9.1 million (-15%)	MISO = $122.4 million Winning Proposal = $103.9 million Difference = -$18.5 million (-15%)

Notes: The cost of the winning proposal for the Hartburg-Sabine Junction 500 kV project is shown above in 2018 dollars to be comparable to the MISO cost estimate. NextEra estimated the project will cost $114.8 million in nominal dollars.
Sources: Duff-Coleman: MISO, Duff-Coleman EHV 345 kV Competitive Transmission Project, Selection Report, December 20, 2016; Hartburg-Sabine Junction: MISO, Hartburg-Sabine Junction 500 kV Competitive Transmission Project, Selection Report, November 27, 2018.

In the competitive process for Hartburg-Sabine Junction, MISO again received a diverse set of proposals, including for structure and conductor types and the 230 kV bus arrangements. MISO found that many of the proposals included well-developed project schedules and plans based on critical path analysis and risk analysis for the projects. MISO noted that several of the proposals went so far as taking soil samples when conducting preliminary fieldwork to assess the risks

56 MISO, Duff-Coleman EHV 345 kV Competitive Transmission Project, Selection Report, December 20, 2016, p. 8.

associated with siting and permitting. In addition, the bids provided schedule guarantees and caps on annual transmission revenues requirements over the first 10 or 40 years.

MISO noted that the selected developer for the Hartburg-Sabine Junction project offered "an outstanding combination of low cost and high value, with best-in-class cost and design, best-in-class project implementation plans, and top-tier plans for O&M [with] an estimated benefit-to-cost ratio of 2.20."[57] The selected developer proposed both a schedule guarantee as well as a cap on total construction costs and the revenue requirements over the first 10 years. MISO valued the enhanced operational and planning flexibility provided by the design proposed by NextEra. Prior to submitting the proposal, NextEra had completed extensive outreach to federal, state, and local authorities and included substantial project-specific planning, site analysis, and field investigation in its implementation plan. Finally, MISO noted that the O&M proposal from NextEra included comprehensive procedures for repairing equipment and extensive experience in hurricane-prone areas.

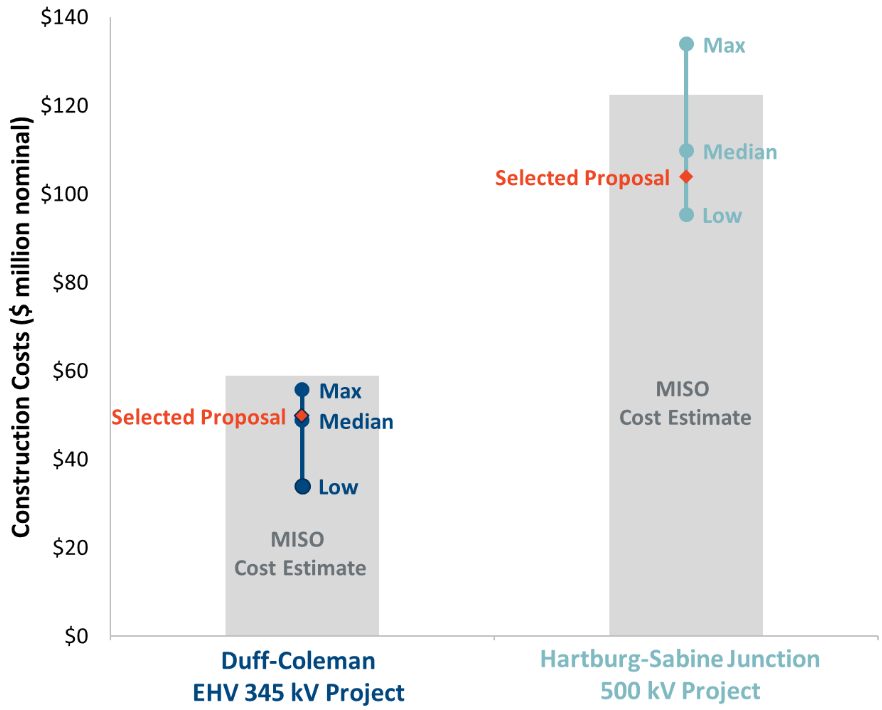
Below, in Figure 17, we show the maximum, minimum, median, and selected proposal's cost estimates for the Duff-Coleman and Hartburg-Sabine Junction projects (as blue and red dots), as well as MISO's own cost estimate (as grey bars). Noticeably, there are large ranges of price estimates for both projects and proposal estimates tend to be less than MISO's own. Additionally, in neither case did MISO select the lowest cost proposal. This demonstrates MISO's thorough consideration of multiple elements of the proposed projects, such as design quality and cost containment mechanisms.

MISO's experience in these two competitive solicitations demonstrates the value of competitive transmission processes; attracting experienced project developers that have brought forward higher quality-proposals at lower cost and with less uncertainty than projects not resulting from competitive solicitations, which will ultimately results in cost savings for end-use customers. Perhaps more important than these project cost saving is the innovation that has occurred over the course of only two competitive solicitations, which promises significant benefits going forward.

---

57 MISO, Hartburg-Sabine Junction 500 kV Competitive Transmission Project, Selection Report, November 27, 2018, p. 2. The winning project's benefit-to-cost ratio of 2.20 compares to MISO's initial estimate of the project's benefit-to-cost ratio of 1.35.

Figure 17
MISO Competitively-Developed Projects Construction Cost Estimates



Notes: The cost of the winning proposal for the Hartburg-Sabine Junction 500 kV project is shown above in 2018 dollars to be comparable to the MISO cost estimate (also in 2018 dollars). NextEra's proposed cost of $114.8 million (in nominal dollars for the completed project).
Sources: Duff-Coleman: MISO, Duff-Coleman EHV 345 kV Competitive Transmission Project, Selection Report, December 20, 2016; Hartburg-Sabine Junction: MISO, Hartburg-Sabine Junction 500 kV Competitive Transmission Project, Selection Report, November 27, 2018.

VIII. Cost of Administering Competitive Processes

We understand from many developers that there are significant costs associated with preparing the proposal package that one must consider when participating in the competitive processes. Further, the ISO/RTOs spend time and budget preparing for the solicitation, conducting the competitive procurement process, analyzing the received proposals, and reporting on the process and the results. The cost of administering the processes are generally recovered from bidders through fees charged to each developer that submits a proposal, which in turn adds to the costs of the project bids. For the developers that are not selected, those costs are borne by the companies themselves.

For the ISOs/RTOs, SPP reported that the internal costs of completing the competitive process for the North Liberal–Walkemeyer 115 kV project was just above $500,000, requiring the recovery of

$47,000 from each of the eleven respondents of the competitive solicitation.[58] In this case, SPP initially charged a fee of $25,000 per submitted proposal and then billed respondents an additional $22,000 following the end of the process to cover SPP's remaining costs, resulting in no direct costs to SPP's transmission customers. SPP's $500,000 evaluation cost for its first competitive solicitations accounted for approximately 3% of the relatively small project's $17 million cost estimate.[59]

PJM structures its fees for competitive projects based on the proposal cost estimate with no fee for project submissions with project costs of less than $20 million, $5,000 for projects from $20 million to $100 million, and $30,000 for all projects that cost more than $100 million.[60] As of December 2017, the fees PJM collected from developers during the five proposal windows in 2016 and 2017 covered 97% of its $1.7 million of total 2016–2017 evaluation costs.[61] PJM approved a total of 139 projects from these proposal windows, resulting in $44,000 of evaluation costs per approved project.

Additional insights about the magnitude of the costs associated with competitive bidding processes for transmission projects can be gained from the experience in the U.K. The U.K. Office of Gas and Electricity Markets (Ofgem), the regulatory agency, reviewed costs from several rounds of successful bidding for off-shore transmission projects in its 2016 justification to expand competitive processes to new onshore transmission investments.[62] This assessment estimated that

---

58 SPP, CTPTF Transmission Owner Selection Process Update, Presented to Strategic Planning Committee, July 7, 2016, p. 33. Available at: https://www.spp.org/documents/39274/spc%20ed%20session%20materials%2020160707.pdf

59 SPP estimated that developers spent $300,000 to $400,000 for each of the 11 proposals submitted to its solicitation for North Liberal – Walkemeyer 115 kV, for a total of $3.3 million to $4.4 million of developer costs. Similar to SPP's costs of administering the competitive solicitation process, these costs are not directly passed through to customers. Prepared Statement of Paul Suskie, Executive Vice President and General Counsel, Southwest Power Pool, Inc., Before the Federal Energy Regulatory Commission, Docket No. AD16-18-000.

60 PJM, Competitive Planning Process Proposal Fee Status Update, December 14, 2017, p. 3. Available at: https://pjm.com/-/media/committees-groups/committees/pc/20171214/20171214-item-06-proposal-fees.ashx

61 PJM, Competitive Planning Process Proposal Fee Status Update, December 14, 2017, p. 4. Available at: https://pjm.com/-/media/committees-groups/committees/pc/20171214/20171214-item-06-proposal-fees.ashx

62 Ofgem, *Extending Competition in Electricity Transmission: Impact Assessment*, May 27, 2016, Sections 3 and 4.7. Available at:

approximately 4% of a large project's total costs are associated with conducting and participating in the competitive bidding process. Of the estimated 4% of total project costs, developers' costs were estimated at approximately 2% of the project cost. The rest of the costs associated with the competitive process is associated with Ofgem's conducting the solicitation at 1%, and the remaining 1% of the process costs were incurred by the network owners and system operator. In comparison, the U.K. experience with offshore transmission shows that three rounds of competitive solicitations for 15 projects achieved estimated savings averaging 23% to 34% of total project costs (as discussed further in Section XII below).

While administrative and developer costs may be significant in the first few rounds of the competitive processes, we expect these costs would decline as experience is gained along the way. We recognize that these costs (including administrative charges) will ultimately need to be recovered by the developers and would thus need to be reflected in the price of their proposal—even if not every developer includes these costs in every bid and every round of competitive solicitation. As a result, these costs will likely be reflected in competitive project cost proposals and thus are already reflected in our estimates of cost savings.

IX. Estimated Cost Savings from Competitive Transmission Processes To Date

As discussed previously, the current experience shows that transmission projects procured through the competitive processes have yielded project offer prices that, on average, were significantly below the projects' initial cost estimates. While many of the winning proposals include cost caps or cost control measures, the completed costs of these projects are not yet known and may exceed the selected projects' offer prices. Cost escalations are often unavoidable due to factors that include inflation, other uncertainties around materials and labor costs, and scope and routing changes that become necessary during the development process. Because the cost of major regional transmission projects typically escalate beyond initial cost estimates, the extent to which the proposed prices of competitive projects are below initial cost estimates provide us only a first order-of-magnitude estimate of the potential cost savings associated with competitive processes. Considering typical cost escalations and international comparisons allows us to further refine these savings estimates.

---

https://www.ofgem.gov.uk/system/files/docs/2016/05/extending_competition_in_electricity_transmission_updated_impact_assessment_0.pdf

Our review of the experience with competitive transmission processes to date indicates a significant potential for cost savings. As documented earlier and summarized in Figure 18 (Column 4) below, the selected proposals from the competitive transmission solicitations were priced 15% to 60% (averaging 40%) below either the initial project cost estimates or the lowest-cost incumbent project offer price. In addition, many winning proposals generally have included cost caps or various cost control measures that are expected limit the risks of significant cost escalations.

In regions with solution-based competitive procurement processes, such as NYISO and PJM, competition can foster additional benefits from innovative project design. For example, in the solicitation process for PJM's Artificial Island Project, many developers proposed a wide range of solutions to meet the identified transmission need. Some developers proposed lower-voltage design options that addressed all the needs identified by PJM at reduced cost and constructability risk. In contrast, some of the solutions offered by developers included significantly longer circuit-miles and only 500 kV options at significantly higher costs. In NYISO, the solutions-based competitive process for the New York transmission projects similarly attracted multiple design innovations that yielded lower costs and higher net benefits.

The analysis of historical average cost escalations for major regional transmission projects presented in Appendix A (and summarized in Column 5 of Figure 18 below) shows that completed costs have historically been 18% to 70% (averaging 34%) above initial project cost estimates. These cost escalations relative to initial estimates typically relate to factors such as inflation, routing adjustments, or environmental permitting-related conditions not reflected in the initial estimates. As further discussed below the final costs of competitively-awarded transmission projects may similarly increase beyond their proposed costs as some of the proposed project costs are indexed to inflation and as developers are able to make certain adjustments as they complete their final routing, siting, and construction. However, some cost caps are binding and the cost containment measures of selected proposals will likely limit the cost increases to levels below those experienced by projects historically.

Figure 18
Estimated Range of Potential Savings from U.S. Competitive Transmission Projects to Date

Region **[1]**	ISO or Incumbent Estimated Cost of Competitive Projects ($million) [2]	Selected Developer's Estimated Cost of Projects ($million) [3]	**Average % Competitive Projects Cost Savings as Proposed*** **[4]**	Average Historical Escalation of Regional Transmission Projects (%) [5]	Expected Cost if Competitive Projects were not subject to Competition ($million) [6]	Potential $ Savings from Competition w/o bid price escalation ($million) [7]	**Potential % Savings without Cost Escalation of Competitive Projects*** **[8]**
CAISO	$1,180	$833	**29%**	41%	$1,667	$834	**50%**
ISO-NE	n/a	n/a	n/a	70%	n/a	n/a	n/a
MISO	$181	$154	**15%**	18%	$215	$61	**28%**
NYISO	$232	$181	**22%**	n/a	$232	$51	**22%**
PJM	$692	$280	**60%**	22%	$847	$567	**67%**
SPP	$17	$8	**50%**	18%	$20	$11	**58%**

Note: *The % shown in Column 4 (Average % Competitive Projects Cost Savings as Proposed) reflects an estimate of final cost savings of competitively-developed projects assuming that their cost escalate similar to the historical average cost escalations in each region (see Appendix A for more details). Column 8 reflects an estimate of final savings assuming no escalations of proposed competitive project costs. For CAISO, the percentage differences shown in columns 4 and 5 are both relative to the high end of the CAISO cost estimate. (Using the low end of the CAISO range would reduce the value in column 4 but increase the value in column 5; as a result, the savings shown in column 8 would be unaffected.) For PJM, competitive project values only reflects the Artificial Island project. For NYISO, the estimate is based only on the Western NY Public Policy Transmission project.

Based on our review of the contracts for the competitively-developed projects in which LS Power is involved, the range of cost caps on the potential cost escalations varies project-by-project based on the specific cost-control commitments made in the developers' proposal.

- *Artificial Island Project (PJM)*: LS Power included a construction cost cap of $146 million that covers all LS-Power-related construction costs of the project, including those associated with obtaining permits, acquiring land, and environmental assessments and mitigations. There are exclusions to the cost cap for costs associated with certain specified types of *force majeure*-type events, taxes, financing, and any incremental costs to the project caused by PJM-directed changes to the project. Finally, the cost cap escalates with inflation until the start of construction based on changes in the Handy-Whitman cost index.
- *Harry Allen–Eldorado 500 kV (CAISO)*: LS Power set a cost cap of $147 million in 2020 dollars. There are exclusions to the cost cap for *force majeure* events, financing costs, and cost increases caused by changes from the ISO or from the incumbent transmission owners at their substations.
- *Duff-Coleman 345 kV*: LS Power agreed to a cost cap where the items excluded from the project's Total Rate Base Cap of $58.1 million were costs from *force majeure* events and on-going O&M costs. Deviations from their cost cap are also allowed for material changes to

the scope of the work outside of the RFP that had not been apparent at the time of the proposal.

The experience in Alberta with the Fort McMurray West 500 kV Transmission Project shows that the costs of competitive transmission projects can rise above the proposed cost estimate due to changes in the transmission route and other factors, just as they can for transmission projects not subject to competition. In the Fort McMurray West's case, a change in route increased the allowed costs of the project by 13% from CAD$1.43 billion to CAD$1.61 billion.[63] In contrast, none of the LS Power commitments identified above include an allowed adjustment due to changes in the project route.

If the resulting cost escalation of competitive projects relative to the price of the selected proposal is less than the historical average cost escalations for regional transmission projects (due, for example, to the cost caps or other contractual cost control measures), the savings from the competitive processes will be higher than the range of savings based on just the difference between accepted project offer prices and initial cost estimates. As shown in the last column of Figure 18 above, savings would range from 22% to 67% if all competitive projects awarded to date could be completed at the proposed cost and not face escalations similar to other regional transmission projects. The more likely outcome, however, is that the savings would fall within the range defined by columns 4 and 8 of Figure 18. Completed costs of competitively-developed projects likely will be above their bid price but on average may not escalate as much as other regional transmission projects have historically due to the additional due diligence conducted by bidders before the competitive process and the cost caps and cost control commitments resulting from the competitive processes. Only if the cost of competitive projects were to escalate by *more* than the average historical transmission projects, would the overall savings be less than the range defined by columns 4 and 8 of Figure 18. This is unlikely because transmission developers with cost commitments have significant incentives to minimize the impact of project changes and cost escalations compared to those without similar cost control mechanisms.

Figure 19 below summarizes the ranges of estimated cost savings based on the experience with competitively-developed transmission projects in the U.S. and abroad. The ranges for the U.S. are generally consistent with the estimated cost savings from competitive transmission development

---

63 See Fort McMurray West 500 kV Transmission Project, available here: https://www.aeso.ca/grid/competitive-process/fort-mcmurray-west-500-kv-transmission-project/ and See AUC Decision 21030-D02-2017, p. 122, available here: http://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2017/21030-D02-2017.pdf

abroad—21% savings in Alberta, 16% in Ontario, 23% to 34% in the U.K., and 25% in Brazil. Based on these ranges and international comparisons we believe competitive transmission development processes can be expected to yield cost savings averaging between 20% and 30%.

Figure 19
Range of Savings from Individual Competitively-Bid Transmission Projects to Date

Region	Estimated Cost Savings	No. of Projects Evaluated	Estimated Cost of Project(s)	Notes
CAISO	29–50%	9	$833 million	Selected proposal costs compared to CAISO initial cost estimate; assuming a range of cost escalation for the selected bid of between zero to the level of historical average cost escalation of transmission projects in CAISO (+41%)
MISO	15–28%	2	$154 million	Selected proposal costs compared to MISO's initial cost estimate; assuming a range of cost escalation for the selected bid of between zero to the historical average cost escalation of transmission projects in MISO (+18%)
PJM	60–67%	1	$280 million	Selected proposal cost (including necessary incumbent upgrades) compared to the lowest-cost solution offered by incumbent in the initial proposal window; assuming a range of cost escalation of between zero to the historical average cost escalation of transmission projects in PJM (+22%)
NYISO	22%	1	$181 million	Selected proposal cost compared to lowest-cost bid from incumbent
IESO	16%	1	CAD 777 million	Selected proposal cost compared to bid from incumbent
AESO	21%	1	CAD 1,614 million	Selected proposal cost compared to AESO initial cost estimate; costs of the winning bid later increased due to changes in route
U.K.	23–34%	15	~£3,000 million	Selected bid cost estimate compared to merchant and regulated counterfactuals estimated by Ofgem
Brazil	~25% (20–40%)	Many	$28 billion	Based on Brazil's experience since 1999 holding auctions for all projects over 230 kV; over 50,000 km of lines built through this process

Source: See Appendix C, Table 24 ("Estimated Savings Across All Regions").
Excludes SPP due to the cancellation of its only competitive project.

The above estimates of cost savings for U.S. competitively-developed transmission projects awarded since 2013 rely on assumptions about possible cost escalations from the proposed cost of the selected bids until they will be completed. The resulting range of estimated U.S. cost savings, however, is consistent with the cost savings realized by the only completed competitively-developed U.S. transmission project—the "Path 15 Upgrade" project consisting of a new 500kV transmission line across the historically heavily congested Path 15 corridor as briefly summarized below.

The **Path 15 Upgrade** project, completed in 2004 and initiated prior to the time period studied in this report, was the first independent, project-financed, greenfield transmission development in the U.S. The developer, TransElect, benefitted from a streamlined permitting process through a public-private partnership with Western Area Power Association (WAPA) that allowed the development team to secure rights of way at lower cost than under traditional utility ownership. The development team structured and competitively procured an innovative fixed-price Engineer-Procure-Construct (EPC) contract that left key decisions about project design and execution to the EPC contractors, thereby providing strong incentives for cost reductions through innovative project design and construction management. This structure combined the selection of qualified contractors with strong incentives for on-time completion of the project. The end result was that the Path 15 Upgrade was completed on time and under budget at a cost of approximately $250 million and well below the $306 million cost initially estimated by PG&E (the incumbent transmission owner) during the planning phase.[64] Even under the assumption that a traditionally-developed Path 15 project could have been constructed at PG&E's initial estimate without any further cost escalation, the realized cost savings were $56 million or 18%. Recognizing that the completed costs of a traditionally-developed Path 15 Upgrade may have been above PG&E's initial cost estimate, the actually-realized construction-related cost savings are even higher than that.

X. Potential Benefits from Expanding Competitive Transmission Processes in the U.S.

The significant cost savings offered by the relatively small number of competitive transmission solicitations to date raise the question how high potential cost savings could be if the scope of competition could be expanded. As mentioned above, the scope of competitive processes has been limited to only 3% of total transmission investments over the last five years. While FERC Order 1000 acknowledged that certain types of projects can be excluded from the competitive processes and FERC has allowed transmission owners to maintain their federal rights of first refusal for upgrades to existing facilities, one of the primary goals of Order 1000 was to advance *cost-efficient development of transmission*. To that end, FERC had identified greater engagement of non-incumbent transmission developers as a means to increase the cost-effectiveness of the nation's transmission infrastructure investments. Given that some ISO/RTOs have successfully implemented a broader-scope of competitive engagement by excluding fewer transmission project

64 Prepared Direct Testimony of Johannes P. Pfeifenberger, FERC Docket Nos. ER14-1332-000, Exhibit No. DAT-8, February 18, 2014, page 38.

types than other regions—and given that there are opportunities for state policymakers to explore changes to or elimination of various existing state laws that impede competition for transmission projects—it is clear that the scope of competition could be expanded substantially.

Having a larger share of transmission investments developed through competitive processes would yield significant customer savings. Based on the experience with competitively-developed transmission in the U.S. and abroad, competitive processes are more likely to be adopted for higher voltage and higher cost projects. Figure 20 below shows that of all RTO-planned transmission investment in PJM and MISO (excluding locally-planned transmission, which includes most upgrades to existing facilities), about half of all MISO projects and 77% of PJM projects cost more than $25 million. Based on voltage, about half of the investments planned by MISO and PJM have involved voltage levels above 300kV and about 66% have been above 150kV.

Figure 20
PJM and MISO Transmission Costs by Total Project Cost and Voltage

	PJM		MISO	
	Costs *$ million*	**Percentage** *% of Total*	**Costs** *$ million*	**Percentage** *% of Total*
Project Costs				
<$25 million	$836	23%	$2,708	48%
$25-50 million	$836	23%	$389	7%
$50-100 million	$1,032	28%	$706	13%
>$100 million	$991	27%	$1,794	32%
Project Voltage				
Up to 138 kV	$994	27%	$1,608	33%
138 - 300 kV	$976	26%	$456	9%
>300 kV	$1,725	47%	$2,870	58%

Sources: 2014–2017 PJM TEAC Staff Whitepapers, PJM Transmission Construction Status Database, and MISO's MTEP Appendix A Status Trackers.

Based on these statistics, we believe the scope of competition could reasonably be expanded from one quarter to one third of total transmission investments. This level of competitively-developed transmission should be achievable, particularly if the current barriers to the development of cost-effective regional and interregional transmission projects to address market efficiency and public policy needs can be reduced. As previously shown in Figure 4, if competition reduced transmission costs by 25% on average, applying these cost savings from competition to one-third of planned U.S. transmission investments would reduce customer costs by approximately $8 billion over the course of five years.

We recognize that long-term cost advantages of competitively-developed transmission projects will likely decline as the innovations and cost-reductions stimulated by competitive processes define best practices that are increasingly applied to a broader set of transmission projects. Customer benefits will be even greater, however, if the innovations and cost-control mechanisms developed through competitive processes can be transferred and applied to the development of transmission projects not subject to competition.

In summary, the current experience with competitive transmission development processes provides a compelling demonstration that competition can create customer benefits consistent with the goals of FERC Order 1000—particularly if a greater proportion of future transmission investments could be developed competitively. One of the most important takeaways from this experience is that reducing the current restrictions imposed on competitive transmission processes is important if meaningful customer savings should be achieved. At minimum, encouraging more competitive transmission development will yield innovation and increased cost discipline on the industry and thereby benefit electricity users. Competitive processes also provide opportunities for all participants to propose and implement contractual mechanisms—such as binding construction cost caps—that would not otherwise be available. As these competitive processes become more widespread and transparent, they will lead all developers to apply more innovative project development and cost controls. The resulting more cost effective transmission development will also benefit transmission owners by reducing rate pressures and by magnifying the benefits and attractiveness of transmission solutions that increasingly compete with local generation alternatives and the declining costs of renewable generation and storage technologies, thereby increasing the total amount of cost-effective transmission investments.

XI. Competitive Transmission Processes in Non-ISO/RTO Regions

FERC Order 1000 applies to regional planning entities in non-ISO/RTO areas in the southeastern and western part of the U.S. These non-ISO/RTO regional planning entities include Southeastern Regional Transmission Planning (SERTP), the South Carolina Regional Transmission Planning (SCRTP), and Florida Reliability Coordinating Council (FRCC) in the southeast; and ColumbiaGrid, Northern Tier Transmission Group (NTTG), and WestConnect in the west. They have developed planning processes to comply with Order 1000 based on a more limited scope of benefits than are considered in most ISO/RTO-administered regional planning processes.[65] The

[65] Chang, *et al.*, The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments, July 2013, p. 32.

most common benefit considered in these non-ISO/RTO regions is the ability of a regional project to displace higher-cost local transmission projects that are included in the base regional system plan, which are often referred to as "cost effective or efficient regional transmission solutions" (CEERTS).

We are not aware of any competitive transmission projects moving forward in any of the non-ISO/RTO regions. The limited scope for competitive projects in these regions likely relates to very restrictive qualification criteria. For example, SERTP substantially limits the scope of projects that can qualify for regional cost allocation and considers a limited set of benefits of those projects. To qualify for regional cost allocation in SERTP, new transmission projects must be 300 kV or greater and at least 50 miles long.[66] Since the region does not currently operate 345 kV transmission facilities, the requirement limits regional projects solely to 500 kV facilities. Similar to other non-ISO/RTO regions, SERTP considers only two project benefits: displacing or deferring projects included in the regional system plan and reducing energy losses. The limited scope of projects that can qualify, the limited benefits considered, and a high benefit-to-cost ratio have resulted in no regional projects being considered in SERTP's planning process. In fact, no transmission developers have pre-qualified to submit regional projects in each of the SERTP planning cycles since 2015.[67]

The other non-ISO/RTO planning regions similarly had limited success in attracting and approving competitively–developed transmission lines:

- WestConnect analyzed nine non-incumbent projects in its 2016–17 planning process, but did not identify any projects that warranted inclusion in the Base Transmission Plan.[68] In addition, WestConnect did not identify any reliability, economic, or public policy needs in the 2016–17 study and therefore did not consider the projects for regional cot allocation.[69]

---

66 SERTP, PJM-SERTP: Order 1000 Biennial Regional Transmission Plan Review Meeting, April 26, 2016, p. 14.

67 For example, see http://southeasternrtp.com/docs/general/2018/2018-October-Pre-qualified-Transmission-Developers-for-the-Upcoming-2019-Planning-Cycle.pdf

68 WestConnect, Regional Study Plan, WestConnect Regional Transmission 2016–17 Planning Cycle, March 16, 2016, p. 39. Available at: https://doc.westconnect.com/Documents.aspx?NID=17180&dl=1

69 WestConnect, Regional Transmission Plan, WestConnect Regional Transmission Planning 2016–17 Cycle, December 20, 2017, p. 39. Available at: https://doc.westconnect.com/Documents.aspx?NID=18010&dl=1

The draft 18/19 Regional Needs Assessment similarly found no regional transmission needs.[70]

- NTTG analyzed six projects in its 2014–2015 regional planning process and identified two regional projects to be more efficient or cost-effective than local projects in the Initial Regional Plan.[71] However, one did not qualify for cost allocation and the other did not request regional cost allocation, which excluded them from the competitive process. No projects were submitted for consideration in the 2016–2017 planning process.[72]
- ColumbiaGrid allows stakeholders to submit suggestions for potential needs during its biennial transmission expansion planning study. In the 2017 study, a stakeholder identified the California 50% RPS as a public policy need. However ColumbiaGrid found that none of its entities must comply with this policy and thus there was no need identified.[73] In the 2019 study, no needs were suggested.[74] As a result, no alternative regional projects were analyzed in either study.
- FRCC has conducted two solicitation windows for competitive proposals and received three proposed regional alternatives to local projects. However, it was subsequently determined that there was no longer a need for the local projects, which means the solicitations did not result in the approval of a competitive project.[75]

---

70 WestConnect, 2018–2019 Regional Planning Cycle, http://regplanning.westconnect.com/2018_19_regional_plng_cycle.htm, accessed March 21, 2019.

71 NTTG, 2014–2015 Regional Transmission Plan, December 30, 2015, p. 3. Available at: https://nttg.biz/site/index.php?option=com_docman&view=download&alias=2595-nttg-2014-2015-regional-transmission-plan-final-12-30-2015&category_slug=2014-2015-regional-transmission-plan-final&Itemid=31.

72 NTTG, 2016–2017 Regional Transmission Plan, December 28, 2017, p. 11. Available at: https://www.nttg.biz/site/index.php?option=com_docman&view=download&alias=2948-nttg-2016-2017-regional-transmission-plan-final-12-28-2017&category_slug=2016-2017-regional-transmission-plan-final&Itemid=31

73 ColumbiaGrid, 2017 Biennial Transmission Expansion Plan, pp. 14–15. Available at: https://www.columbiagrid.org/download.cfm?DVID=4912

74 ColumbiaGrid, 2019 Biennial Transmission Expansion Plan, p. 19. Available at: https://www.columbiagrid.org/client/pdfs/2019%20Biennial%20Transmission%20Expansion%20Plan%20(BTEP).pdf

75 For example, see FRCC Biennial Transmission Planning Process (BTPP): Step 3&4, February 25, 2016, p. 5.

- SCRTP has set similar limits on competitive regional projects as SERTP, including that the project must be above 230 kV, longer than 50 miles, cost more than $10 million, and be developed as a greenfield facility.[76] SCRTP has received no proposals for alternative projects to date.

XII. International Experience with Competitive Transmission Processes

The use of competitive transmission processes has not been limited to the U.S. They have been utilized in other countries, including Canada, the U.K., Brazil, Chile, and Australia.

In **Canada**, three competitive transmission solicitations have been completed; one in Alberta and two in Ontario. In both provinces, the price of the winning bids were significantly lower than ISO planning cost estimates or incumbent cost estimates, but in both cases the projects faced cost escalations. In Alberta, cost estimates for the Fort McMurray West 500 kV Transmission Project were originally estimated to be CAD $1.43 billion, 21% lower than the initial AESO estimate of CAD $1.8 billion. Due to a change in project routing (which would have increased the AESO's estimate), the final costs for the project increased to CAD $1.61 billion.[77] The AESO notes that the competitive bidding of the project, which was energized in March 2019 on budget and three months ahead of schedule,[78] provided Alberta ratepayers over $400 million in savings.[79] Similarly, the costs of Ontario's East-West Tie Line project increased from 2020 CAD $439 million to 2020 CAD $777 million, which still falls 16% below the incumbent transmission owner's (Hydro One's) estimate for a comparable line. This range of savings from competitive transmission in Alberta

---

76 SCRTP, Transmission Planning Process (Attachment K), Section VII. Regional Transmission Planning, October 15, 2013, p. 288. Available at: https://www.scrtp.com/document-library

77 See Fort McMurray West 500 kV Transmission Project, available here: https://www.aeso.ca/grid/competitive-process/fort-mcmurray-west-500-kv-transmission-project/
See also AUC Decision 21030-D02-2017, p. 122, available here: http://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2017/21030-D02-2017.pdf

78 See "Alberta PowerLine places 500-kV transmission line into service," March 29, 2019. Available at : https://ml.globenewswire.com/Resource/Download/9eb84e58-d533-4b74-bffb-4e2340bbf6da

79 The AESO also notes that the winning bid included all project costs while the AESO's initial estimate included only construction costs, estimating that "competition cost savings for Alberta ratepayers is conservatively estimated to be over $400 million." See: https://www.aeso.ca/grid/competitive-process/fort-mcmurray-west-500-kv-transmission-project/

(21%) and Ontario (16%) is within the range of estimated savings achieved by the competitive solicitations in the U.S.

In **the U.K.**, competitive solicitations have been conducted for offshore transmission by the Office of Gas and Electricity Markets (Ofgem, the national regulator) since 2009. Through three separate Offshore Transmission Owner ("OFTO") Tender Rounds, investors competed to own, finance, and operate transmission assets of about £3,000 million.[80] OFTO Rounds 1, 2, and 3 had estimated savings ranging from £683 million to £1,092 million.[81] The positive experience with competition in offshore transmission—accounting for estimated cost reductions averaging 23%–34% (net of the cost of conducting the process) compared to regulated counterfactuals with an estimated range of 14% to 45% for the individual rounds—has led Ofgem to complete three additional rounds for offshore wind and expand the scope of competitive solicitations to include all large new onshore transmission investments as well.[82]

In **Brazil**, competitive transmission auctions have been conducted by ANEEL, the Brazilian Electricity Regulatory Agency, since 1999 to select who builds, operates, and owns transmission assets.[83] These auctions operate by offering maximum annual revenue requirements (estimated based on typical project costs) and having bidders propose lower revenue requirements, with the

---

80 The Ofgem offshore transmission policy design is available here: https://www.ofgem.gov.uk/electricity/transmission-networks/offshore-transmission/offshore-transmission-policy-design

Total value of competitively-developed projects estimated based on reported savings.

81 Ofgem, *Evaluation of OFO Tender Round 2 and 3 Benefits*, March 2016, available here: https://www.ofgem.gov.uk/publications-and-updates/evaluation-ofto-tender-round-2-and-3-benefits

82 For an update on competition in U.K. onshore electricity transmission see: https://www.ofgem.gov.uk/publications-and-updates/update-competition-onshore-electricity-transmission

For a summary of off-shore experience and justification for introducing competition to the onshore network, see: https://www.ofgem.gov.uk/system/files/docs/2016/05/extending_competition_in_electricity_transmission_updated_impact_assessment_0.pdf

83 For a summary of Brazil's experience with competitive transmission see: Chang and Pfeifenberger (2015), Competitively-Bid Transmission Investments in the U.S. and Abroad, August 4, 2015, pp. 14–15.

See also Ofgem (2013), *Integrated Transmission Planning and Regulation Project: Review of System Planning and Delivery,* Prepared for Ofgem, June 2013, Appendix C3, Available at: https://www.ofgem.gov.uk/ofgem-publications/52727/imperialcambridgeitprreport.pdf lowest-cost bid selected as the winner. Between 1999 and 2008, 87 transmission concessions were auctioned, receiving a total of 399 bids by 112 companies and consortiums, 57% of which were foreign bidders.[84] The first 15 years of auctions saw 50,000 km of new transmission built through this competitive process, with a total investment of $28 billion. The total maximum annual revenue requirement on this investment would have been $4.45 billion, which the ANEEL auctions reduced to $3.35 billion, an average 25% cost reduction,[85] with ranges from 20% to 40% for individual projects and individual bids offering cost reductions as high as 58%.[86] The experience in Brazil further showed that the size of the cost reduction is positively correlated with the number of bidders, illustrating that more competition creates stronger downward pressure on costs.[87]

In addition to these experiences, competitive transmission development processes have been utilized in Chile and Australia.[88] In Australia, the state of Victoria has introduced "contestability" for generation interconnections to the transmission grid.[89]

Despite diverse international experiences with competitive transmission and large variety of competitive mechanism, the effects of competitive transmission are clear: more innovation and more cost-effective transmission.

---

84 Ofgen (2013) Appendix C3.

85 See Chang and Pfeifenberger (2015) and Ofgem (2013), Appendix C3.

86 Ofgem (2013), Appendix C3, p. 69.

87 *Id.*

88 For a summary of the experience with competitive processes in Chile, see: Ofgem (2013), Appendix C4, p. 72.

89 For example, see Allens-Linklaters, *A new Framework for Transmission Network Connections*, July 30, 2018. Available at: https://www.allens.com.au/pubs/ener/cuener30jul18.htm

See also Freedman, *Transmission Connection Contestability: It's Finally Here, June 5, 2017*. Available at: https://www.linkedin.com/pulse/transmission-connection-contestability-its-finally-here-freedman/

Appendix A: Average Historical Cost Escalations of Transmission Projects Relative to Initial Cost Estimates

To better understand the potential savings offered by competitive processes, we gathered data to analyze the extent to which transmission projects experience cost escalations relative to initial cost estimates. To do so, we reviewed available transmission project cost reports to document deviations between a project's initial cost estimates and its final costs (as reported at the time a project is placed in-service).

In this analysis, we identified the respective projects' initial cost estimates as documented in various project cost tracking reports and other databases made available by CAISO, SPP, MISO, and PJM. With the exception of CAISO, which prepares initial project cost estimates for all CAISO-planned projects, the available initial estimates of project costs in SPP, MISO, and PJM are prepared by the sponsoring incumbent transmission owners. We compare these initial cost estimates to the final project costs as reported by SPP, MISO, and PJM and as recently filed by CAISO transmission owners at FERC in response to the CPUC complaint (as noted earlier).[90]

The historical cost escalations we observed for transmission projects are summarized below in Figure 21 through Figure 25 for MISO, SPP, CAISO, PJM, and ISO-NE. While there are examples of project cost estimates that closely matched realized project costs and some transmission developers likely prepare more accurate estimates than others, there have been large cost escalations for some of these transmission projects. These cost escalations may be driven be inflation during the multi-year project development process and added costs to comply with conditions imposed during the permitting and siting process. On average, these cost escalations ranged from 18% average cost escalations for the reported project types in MISO and SPP to 41% in CAISO and 70% in ISO-NE. The high average cost escalation in ISO-NE is due primarily to the cost escalations on three major projects—the Southwest Connecticut, Greater Springfield, and the

90 Relying on the transmission owners' own initial project cost estimates may result in a more conservative estimate of cost escalation rates (if any) when compared to competitive project cost savings, given that these initial estimates may not be prepared like ISO/RTO cost estimates. Rather, initial project costs may have been estimated to include additional contingencies to hedge against cost escalations.

Rhode Island Reliability Projects—each of which was completed at more than twice the initial cost estimate.[91]

We recognize that a portion of the observed escalations reflect inflation and justified design changes between the point in time when the initial estimates were made and the time when the projects were placed into service. We also recognize that several of the ISOs/RTOs have recently implemented cost estimation standards and project cost tracking mechanisms intended to improve transparency and the quality of the cost estimates.[92] In fact, where publicly available, these cost tracking mechanisms allowed us to assemble the data analyzed in this report. We use the documented "typical" cost escalations simply to provide reference levels against which to compare the proposed and estimated realized costs of competitively-developed projects. Since the competitively-developed projects may experience cost escalations as well, we present how the costs of both types of transmission projects compare to their initial cost estimates.

The absence of cost-tracking mechanisms in some of the ISO/RTOs, such as CAISO and NYISO, makes it very challenging to observe, document, and monitor project cost changes as projects progress through the development phases. In CAISO, the data filed by the major transmission owners in two FERC complaints shows that the cost escalations relative to CAISO's initial cost estimates are high—with final project costs averaging 41% higher than the upper end of the *CAISO's initial estimates* as summarized in Figure 23 below.[93] We were not able to collect or analyze such data for NYISO.

---

91 NextEra Energy Transmission (NEET), *Greater Boston Cost Comparison*, Presented to ISO-NE Planning Advisory Committee, 02/03/2015, p. 5. Accessed at https://www.iso-ne.com/static-assets/documents/2015/02/a2_nht_greater_boston_cost_analysis_public.pdf

92 See, for example, Pfeifenberger and Hou, *Summary of Transmission Project Cost Control Mechanisms in Selected U.S. Power Markets*, October 2011. Available at: https://brattlefiles.blob.core.windows.net/files/6222_summary_of_transmission_project_cost_control_mechanisms_in_selected_us_power_markets_pfeifenberger_hou_oct_2011.pdf

93 FERC Docket Nos. ER16-2320 and ER17-45.

Figure 21
MISO Historical Cost Escalation for Base Reliability, Multi-Value, and Market Efficient Projects (2015–2017 in-Service, 2018 in-Service or Under-Construction)

Year	Number of Facilities	TO Estimate Provided to MISO After Approval ($million)	TO Latest Cost Estimate Provided to MISO ($million)	Cost Escalation %
2015	55	$1,711	$1,672	−2%
2016	110	$1,251	$1,542	23%
2017	62	$780	$822	5%
2018Q1	77	$2,217	$3,017	36%
Total	**304**	**$5,960**	**$7,053**	**18%**

Notes: Cost estimates shown are for in-service & under construction Base Reliability, MVP, and MEP facilities, as reported in MISO's MTEP Appendix A Status Trackers. Cost Change equals TO Latest Cost Estimate Provided to MISO over TO Estimate Provided to MISO After Approval minus 1.

Figure 22
SPP Historical Cost Escalation for Completed Transmission Projects

SPP Portfolio	Initial TO Cost Estimate ($million)	Latest Cost Estimate Tracked by SPP ($million)	Cost Escalation %
Balanced Portfolio	$691	$831	20%
Priority Projects	$1,145	$1,349	18%
ITP Portfolio Projects with Final Cost Estimates (2012 to 2017)	$192	$211	10%
Total	**$2,028**	**$2,391**	18%

Notes: Balanced Portfolio data comes from the 2017 Q2 SPP Quarterly Project Tracking Report.
Priority Projects data comes from the 2017 Q4 SPP Quarterly Project Tracking Report.
ITP Portfolio data comes from the 2019 Q1 SPP Quarterly Project Tracking Report, Appendix 1.

Figure 23
CAISO Historical Cost Escalation for Completed Transmission Projects

Project	TO Cost Estimate submitted to CAISO/CPUC ($million)	CAISO Estimate ($million)	Estimated Final Cost ($million)	Estimated Final Cost relative to TO's CAISO/CPUC Submitted Cost (% change)	Estimated Final Cost relative to CAISO Estimate (% change)
Wheeler Ridge Junction 230kV Substation	$155	$140	$151	−3%	8%
Spring 230kV Substation	$48	$45	$98	104%	118%
Estrella 230kV Substation	$34	$45	$96	179%	113%
Martin 230kV Bus Extension	$129	$129	$285	121%	121%
Midway-Andrew 230kV Project	$154	$150	$198	29%	32%
Lockeford-Lodi Area 230kV Development	$103	$105	$163	58%	55%
Oro Loma 70kV Reinforcement	$46	$46	$30	−34%	−34%
ECO Substation	$273	–	$410	50%	–
New TL ES-Ash #2	$22	< $50M	$5	−78%	–
IV West Generator Interconnection	$2	–	$1	−47%	–
Talega-Add Synchronous Condensers	$64	$72	$81	26%	12%
Shunt Reactor on Suncrest 500kV Bus	$11	–	$10	−10%	–
Pio Pico Energy Ctr. Gen. Interconnect	$9	–	$10	2%	–
Relocate South Bay Substation	$129	$129	$121	−7%	−6%
Talega Bank 50 Replacement	$6	$6	$2	−61%	−64%
TL13821 and TL13828-Fanita Junction Enhancement	$41	<50M	$35	−15%	–
Encina Bank 61	$11	<50M	$8	−29%	–
Tehachapi	$1,800	–	$2,350	31%	–
Total	$3,037	$867	$4,053	**33%**	**41%***

Notes: These Projects are not the complete universe of CAISO projects.
* Percentages exclude projects with no specific CAISO estimates. Estimated Final Cost relative to its CAISO/CPUC Submitted Cost (% change) equals Estimated Final Cost ($million) divided by Cost Estimate submitted by TO CAISO/CPUC minus 1. Estimated Final Cost relative to CAISO Estimate equals Estimated Final Cost ($million) divided by Upper End of CAISO Estimate ($million) minus 1. CAISO typically reports a high and low cost estimate for transmission projects. This table reports CAISO's high estimate as it is generally more consistent with the TO-prepared estimates as submitted to the CPUC as shown above. Measuring cost escalations relative to the CAISO's low estimate would yield higher percentage increases.
Source: Exhibit PUC-0015 in FERC Docket No. ER16-2320-000; SDG&E Responses to data requests issued in FERC No. EL17-45; 2016–2017 CAISO Draft Transmission Plan Stakeholder Meeting; and SCE's 2016 Q4 Quarterly Report.

Figure 24
PJM Historical Cost Escalation for Baseline and Network Projects
(2014–2017 in-Service or Under-Construction Baseline & Network Upgrade Projects)

Year	Initial TO Cost Estimate *(provided at time of PJM Advisory Committee recommendation)* ($million)	Latest TO Cost Estimate *(reported by PJM Cost Allocation Tracking)* ($ million)	Cost Escalation %
2014	$822	$971	18%
2015	$1,722	$2,124	23%
2016	$768	$940	22%
2017	$382	$485	27%
Total	**$3,695**	**$4,520**	**22%**

Notes: Table reflects only projects with reported initial cost data and latest cost data. Cost Escalation equals Latest TO Cost Estimate over Initial TO Cost Estimate minus 1. Projects are categorized into years based on PJM provided "DisplayServiceDate" variable in PJM Transmission Construction Status Database. Supplemental and TO Initiated projects are only notified to TEAC but standard reporting of costs are not tracked by PJM's Transmission Construction Status Database, so they are not reflected in this data.
Source: Initial cost estimates from 2014–2017 PJM TEAC Staff Whitepapers Latest Cost Estimates from PJM Transmission Construction Status Database

Figure 25
ISO-NE Historical Cost Escalations for Major Transmission Projects

Project	Initial TO Cost Estimate ($million)	Final TO Cost Estimate ($million)	Cost Escalation %
Scobie-Tewksbury	$123	$120	−2%
Wakefield-Woburn	$107	$137	28%
Mystic Woburn	$75	$82	9%
Stoughton Cable Project (Phase I & II)	$213	$317	49%
Southwest Connecticut	$690	$1,415	105%
Norwalk Reliability	$128	$234	83%
Worcester Reliability	$7	$33	377%
Long Term Lower SEMA	$107	$105	−2%
Millstone DCT elimination	$22	$39	76%
NEEWS–Greater Springfield	$350	$759	117%
NEEWS–Rhode Island Reliability	$150	$315	110%
Merrimack Valley/North Shore Project	$43	$62	45%
NEEWS–Interstate Reliability	$400	$542	35%
Stamford Reliability	$49	$42	−15%
Total	**$2,464**	**$4,201**	**70%**

Notes & Sources:
Cost information on Scobie-Tewksbury, Wakefield-Woburn, and Mystic Woburn based on ISO-NE Regional System Plan (RSP) Pool Transmission Facility estimate cost, sourced from ISO-NE Final RSP 18 Project List–March 2018, accessed at https://www.iso-ne.com/system-planning/system-plans-studies/rsp/.
Cost information shown for rest of the projects based on: NextEra Energy Transmission (NEET), Greater Boston Cost Comparison, Presented to ISO-NE Planning Advisory Committee, 02/03/2015. Accessed at https://www.iso-ne.com/static-assets/documents/2015/02/a2_nht_greater_boston_cost_analysis_public.pdf.

Appendix B: List of Acronyms

AC	Alternating Current
AESO	Alberta Electric System Operator
BGE	Baltimore Gas and Electric
CAD	Canadian Dollars
CAISO	California Independent System Operator
CPUC	California Public Utilities Commission
CREZ	Competitive Renewable Energy Zone (Texas, ERCOT)
DCR	Delaney-Colorado River (CAISO)
DOE	Department of Energy
EEI	Edison Electric Institute
EIA	Energy Information Administration
ERCOT	Electric Reliability Council of Texas
FERC	Federal Regulatory Energy Commission
IESO	Independent Electricity System Operator (Ontario)
ISO	Independent System Operator
ISO-NE	Independent System Operator of New England
ITP	Integrated Transmission Plan (SPP)
kV	Kilovolt
MEP	Market Efficiency Project (MISO)
MISO	Midcontinent Independent System Operator
MTEP	MISO Transmission Expansion Plan
MVP	Multi-Value Project (MISO)
NEET	NextEra Energy Transmission
NTC	Notification to Construct (SPP)
NYISO	New York Independent System Operator
PG&E	Pacific Gas & Electric
PJM	PJM Interconnection
PSEG	Public Service Enterprise Group
PUC	Public Utility Commission
PUCT	Public Utility Commission of Texas
RSP	Regional System Plan (ISO-NE)
RTO	Regional Transmission Organization
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SPP	Southwest Power Pool
TEAC	Transmission Expansion Advisory Committee (PJM)
TO	Transmission Owner
TPIT	Transmission Project and Information Tracking (ERCOT)
WECC	Western Electricity Coordinating Council

Appendix C: Detailed Data Tables

Figure No. In Report	Figure Title	Data Table Number
1	U.S. Annual Transmission Investments	Table 1
2	2013–2017 FERC-Jurisdictional Transmission Investments With Full and Limited Stakeholder Review within ISO/RTO Regional Planning Processes	Tables 2 and 3
3	Cost Savings for Competitive Projects in CAISO and MISO	Table 23
4	Potential 5-Year Cost Savings from Increasing U.S. Transmission Investments Subject to Competition	n/a
5	U.S. Annual Transmission Investments (2010–2017)	Table 1
6	Competitively-Developed Projects in FERC-Jurisdictional Regions and Selection Year	Table 2
7	Competitive Transmission Qualification Processes of U.S. ISOs/RTOs	Table 4
8	Transmission Additions Subject to Full ISO/RTO Planning Processes	Table 3
9	Experience with Competition in FERC-Jurisdictional ISO/RTO Regions	Table 5
10	North American Competitive Transmission Projects Summary	Table 6
11	MISO and SPP Competitive Projects Savings Summary	Tables 7 and 8
12	CAISO Competitive Projects Summary	Table 9
13	Selected PJM Competitive Projects Savings Summary	Table 10
14	NYISO Competitive Project Savings Summary	Table 11
15	AESO and Ontario Competitive Projects Summary	Tables 13 and 14
16	MISO Competitive Transmission Solicitations	n/a
17	MISO Competitively-Developed Projects Construction Cost Estimates	n/a
18	Estimated Savings from Competitive Projects in U.S. ISOs and RTOs	n/a
19	Range of Savings from Competitively-Bid Projects across All Regions	Table 24
20	PJM and MISO Transmission Costs by Total Project Cost and Voltage	n/a
21	MISO Historical Cost Escalation for Base Reliability, Multi-Value, and Market Efficient Projects (2015–2017 in-Service, 2018 in-Service or Under Construction)	Table 17
22	SPP Historical Cost Escalation for Completed Transmission Projects	Table 16
23	CAISO Historical Cost Escalations for Completed Transmission Projects	Table 18
24	PJM Historical Cost Escalation for Baseline and Network Projects	Table 15
25	ISO-NE Historical Cost Escalations for Major Transmission Projects	Table 19

Table 1: U.S. Annual Transmission Investments Reported in FERC Form 1 ($million)

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2013-2017 Total	1999-2017 CAGR
CAISO	$184	$226	$176	$157	$334	$333	$304	$293	$398	$710	$645	$678	$1,003	$827	$621	$1,635	$1,683	$936	$3,488	$3,185	$2,647	$2,513	$2,422	$1,824	**$12,591**	**10%**
ISO-NE	$143	$91	$100	$111	$83	$92	$127	$167	$171	$203	$203	$309	$705	$785	$2,118	$651	$652	$604	$1,434	$1,769	$1,375	$1,696	$1,420	$1,228	**$7,488**	**15%**
MISO	$418	$332	$383	$421	$351	$338	$333	$1,255	$457	$532	$620	$928	$1,235	$1,233	$1,169	$1,470	$1,421	$1,049	$1,324	$2,476	$2,685	$3,002	$4,023	$3,345	**$15,530**	**14%**
NYISO	$99	$120	$96	$94	$85	$86	$113	$147	$114	$76	$171	$239	$326	$375	$460	$241	$522	$678	$327	$441	$492	$469	$543	$647	**$2,592**	**12%**
PJM	$502	$601	$537	$399	$349	$464	$597	$420	$330	$452	$409	$583	$1,179	$824	$1,278	$1,469	$1,854	$3,405	$2,900	$4,080	$6,602	$7,265	$7,088	$6,433	**$31,469**	**16%**
SPP	$140	$151	$143	$115	$72	$113	$169	$222	$210	$173	$185	$199	$231	$305	$502	$434	$825	$602	$1,165	$961	$2,094	$896	$1,362	$889	**$6,202**	**12%**
Subtotal FERC-jurisdictional RTO/ISOs	$1,486	$1,522	$1,435	$1,298	$1,275	$1,426	$1,642	$2,505	$1,680	$2,146	$2,233	$2,936	$4,680	$4,349	$6,147	$5,901	$6,957	$7,273	$10,637	$12,912	$15,895	$15,841	$16,858	$14,366	**$75,873**	**14%**
ERCOT	$185	$121	$53	$103	$99	$138	$146	$432	$417	$328	$327	$358	$533	$575	$530	$455	$840	$1,171	$1,017	$5,283	$865	$923	$2,000	$1,143	**$10,213**	**12%**
Subtotal U.S. ISO/RTOs	$1,672	$1,643	$1,488	$1,401	$1,374	$1,563	$1,788	$2,937	$2,097	$2,473	$2,560	$3,294	$5,213	$4,924	$6,677	$6,356	$7,797	$8,444	$11,654	$18,195	$16,760	$16,764	$18,858	$15,509	**$86,086**	**14%**
Other WECC	$316	$256	$247	$191	$406	$315	$213	$410	$327	$548	$572	$374	$469	$753	$736	$858	$1,695	$713	$815	$1,169	$758	$1,318	$1,038	$923	**$5,208**	**6%**
Southeast & Other	$536	$565	$580	$359	$351	$429	$616	$869	$890	$922	$979	$896	$1,331	$1,136	$1,383	$1,508	$1,335	$1,826	$1,819	$1,647	$1,631	$1,868	$1,911	$2,322	**$9,379**	**10%**
Total US Reported to FERC	**$2,523**	**$2,464**	**$2,315**	**$1,951**	**$2,131**	**$2,307**	**$2,617**	**$4,216**	**$3,314**	**$3,943**	**$4,112**	**$4,564**	**$7,012**	**$6,813**	**$8,796**	**$8,722**	**$10,827**	**$10,983**	**$14,289**	**$21,012**	**$19,150**	**$19,949**	**$21,808**	**$18,755**	**$100,673**	**12%**

Notes:

Not all ERCOT TOs filed FERC Form 1. Therefore, for 2010 through 2017, ERCOT's Transmission Project and Information Tracking (TPIT) data are provided. ERCOT's TPIT can be accessed at: http://www.ercot.com/gridinfo/sysplan

Data for 2010 through 2017 reflect actual utility membership in an ISO/RTO for a given year. Data for 1994 through 2009 reflect membership as of 2010. Investments shown in nominal dollars.

Data does not include transmission additions by entities that do not file FERC Form 1, except for ERCOT for 2010-2017, which is based on TPIT.

Sources:

Total Transmission addition figures are calculated using FERC Form 1 data in conjunction with EIA 861 data.

Table 2: Competitively-Developed Projects by Region and Selection Year ($million)

Year		CAISO	ISO-NE	MISO	NYISO	PJM	SPP	All FERC Jurisdictional ISO/RTOs	ERCOT	All ISOs/RTOs	Total US
[1]		[2]	[3]	[4]	[5]	[6]	[7]	[8]=sum([2]:[7])	[9]	[10]=sum([8]:[9])	[11]
2013	[a]	$144	—	—	—	—	—	$144	—	$144	$144
2014	[b]	$148	—	—	—	$90	—	$238	—	$238	$238
2015	[c]	$425	—	—	—	$912	—	$1,337	—	$1,337	$1,337
2016	[d]	$133	—	$50	—	$471	$8	$662	—	$662	$662
2017	[e]	—	—	—	$181	$142	—	$323	—	$323	$323
Total Estimated Competitive Project Costs Selected (2013 - 2017)	[f]=sum([a]:[e])	$851	—	$50	$181	$1,615	$8	$2,705	—	$2,705	$2,705
Total Reported FERC Form 1 Investment in 2013 - 2017	[g]	$12,591	$7,488	$15,530	$2,592	$31,469	$6,202	$75,873	$10,213	$86,086	$100,673
Total Estimated Competitive Project Costs Selected in 2013-2017 (% of 2013-2017 Total Investment)	[h]=[f]/[g]	6.8%	0.0%	0.3%	7.0%	5.1%	0.1%	3.6%	0.0%	3.1%	2.7%

Notes:

[f]: Estimated Competitively-Proposed Project Costs reflect project cost estimates provided during Project Selection Years. Projects that have been canceled or put on hold are included.

[g]: Not all ERCOT TOs filed FERC Form 1. Therefore,ERCOT's TPIT reported cost data are shown. ERCOT's TPIT accessed from: http://www.ercot.com/gridinfo/sysplan

Sources:

[a]-[e]: Sources for Competitively-Proposed Project cost estimates are shown in the table 6, 7, 8, 9, and 11. Data for PJM comes from TEAC Project Statistics presentations for 2017 and 2018.

[g]: Calculated using FERC Form 1 data in conjunction with EIA 861 data, with the exception of ERCOT.

Table 3: Transmission Additions Subject to Full ISO/RTO Planning Processes

		Years Reviewed	FERC Jurisdictional Additions by Transmission Owners (nominal $million) *(based on FERC Form 1 Filings)*	Investments Approved Through Full ISO/RTO Planning Process (nominal $million)	% of Total FERC Jurisdictional Investments Approved Through Full ISO/RTO Planning Process	% of Total FERC Jurisdictional Investments With Limited ISO/RTO Review
		[1]	[2]	[3]	[4]=[3]/[2]	[5]= 1-[4]
CAISO	[a]	2014 - 2016	$7,528	$4,043	54%	46%
ISO-NE	[b]	2013 - 2017	$7,488	$5,300	71%	29%
MISO	[c]	2013 - 2017	$15,530	$8,068	52%	48%
NYISO	[d]	2013 - 2017	$2,592	n/a	n/a	n/a
PJM	[e]	2013 - 2017	$31,469	$14,458	46%	54%
SPP	[f]	2013 - 2017	$6,202	$4,226	68%	32%
Total	[g]	-	**$70,810**	**$36,095**	**53%**	**47%**

Notes:

[a]: CAISO data only reflects transmission additions/approved investments of PG&E, SCE, and SDG&E.

[d][3]: There is no data available on investments approved by NYISO.

[e]: Supplemental and Transmission Owner Initiated projects were excluded from these calculations, as they are not assesed for need or cost efficiency by PJM.

[f]: Values for 2013 and 2017 contain only partial December values, due to data limitations.

[g]: Totals in columns [2], [3] are for values as shown.

[g][4]: Percentage shown does not include NYISO.

[2]: Total FERC Form 1 transmission additions over indicated time periods.

[3]: Total value of transmission additions placed in-service over indicated time periods, approved through ISO/RTO processes. For annual data, please see supplemental table Table 21: Approved Investment By RTO.

[3][c]: MISO data reflects only fully completed projects, per MISO project tracking reports.

Sources:

[2]: Data are from FERC Form 1, analyzed in conjunction with EIA 861 data, shown in nominal dollars.

[3]: Shown in nominal dollars. Sources for each row are noted below.

[a]: Formal Complaint of California Public Utilities Commission, et. al. under Docket No. EL17-45.

[b]: https://www.iso-ne.com/about/key-stats/transmission/

[c]: MISO Transmission Expansion Plan (MTEP) In-Service Project List as of 1/9/2018. Accessed on 4/10/2018. A current version of the List is available on the MISO website.

[e]: PJM Cost Allocation Database was used for costs for Baseline Projects; PJM Construction Cost Database was used for Network upgrades.

Cost allocation database available at: http://www.pjm.com/planning/rtep-upgrades-status/cost-allocation-view

Construction Cost database available at: http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx

[f]: SPP STEP Reports (2014-2018).

Table 4: Competitive Transmission Project Eligibility for Processes of U.S. ISO/RTOs

		CAISO	ISO-NE	MISO	NYISO	PJM	SPP
		[1]	[2]	[3]	[4]	[5]	[6]
Types of Projects Eligible for Competition	[a]	Reliability, Economic, Public Policy	Reliability, Economic, Public Policy	Market Efficiency (MEP), Multi-Value (MVP)	Reliability, Economic, Public Policy	Reliability, Economic, Public Policy	ITP, High Priority, Interrigional
Exclusions							
Exclusions for Reliability Projects	[b]		✓ (Based on Need Date)	✓ *		✓ (Based on Need Date)	✓ (Based on Need Date)
Exclusions for Local Cost Allocated Projects (per Order 1000)	[c]	✓	✓	✓	✓	✓	✓
Exclusion of Upgrades (per Order 1000)	[d]	✓	✓	✓	✓	✓	✓
Exclusions Based on Voltage							
Voltage > 300 kV	[e]						
Voltage 200-300 kV	[f]			✓ ** (For MEP)			
Voltage 100-200 kV	[g]	✓		✓ ** *(For MEP)*		✓ ***	
Voltage < 100 kV	[h]	✓	✓	✓ **		✓ ***	✓

Notes and Sources:

Additionally, competitive transmission may be precluded in certain states, due to state Right of First Refusal (ROFR) provisions.

*****In MISO, projects that are **only** classified as Baseline Reliability Projects are locally allocated (regardless of voltage), making them ineligible for competitive processes. Projects designated as Baseline Reliability Projects **and** MEPs/MVPs are cost-allocated as though they are MEPs/MVPs.

******MISO limits competition to MEPs and MVPs; MEPs must have a total cost of at least $5 million and a minimum voltage of 230 kV; MVPs must have a total cost of at least $20 million and a minimum voltage of 100 kV; see MISO Tariff Attachment FF, Sections II.B. and II.C.

*******PJM has exceptions to these exclusions on lower voltage facilities for specific types of reliability violations. These exceptions are detailed in PJM Manual 14F Section 5.3.4.

[c] & [d]: Order No. 1000 did not mandate inclusion of Locally Cost Allocated projects or Upgrades.

[1][a][d][g][h]: CAISO Memo on Decision on the ISO 2016-2017 Transmission Plan, March 8, 2017, p. 8.

[1][c]: CAISO 2017-2018 Transmission Plan, p. 35.

[2][a][b]: ISO-NE Overview of the Transmission Planning Process and the Role of ISO New England, December 3rd, 2015 Consumer Liaison Group Meeting, pp. 8-9.

[2][c][d]: ISO New England Inc. Transmission, Markets, and Services Tariff Section II, Schedule 12, Transmission Cost Allocation on and After January 1, 2004, p. 371.

[2][h]: ISO New England Inc. Transmission, Markets, and Services Tariff Section II, Schedule 12, Transmission Cost Allocation on and After January 1, 2004, p. 109.

[3][a][c]: Transmission Planning Business Practices Manual, Effective Dec 1, 2017 pp. 21-22.

[3][b]: MISO Tariff Attachment FF Sections II.C and III.B.

[3][d]: MISO FERC Electric Tariff, Attachment FF, Section VII.A.

[3][f][g][h]: MISO Business Practice Manual 020, Section 7.4 and 7.5

[4][a][c][d]: NYISO Tariff OATT Attachment Y, 31.1.2, 31.1.4, 31.1.5, and 31.6.4.

[5][a][b]: PJM Manual 14F, Section 1.

[5][c][d][g][h]: PJM Manual 14F, Section 5.3.

[6][a][b][c][d][h]: SPP Open Access Transmission Tariff, Attachment Y, Section I.

Table 5: Summary of Experience with Competition in U.S. ISO/RTOs and Canadian ISOs in Alberta and Ontario

Regions		Governing Regulatory Order for Competition	Competitive Processes Completed	Process Type	Awards	Cost-containment	Competitively-Solicited Projects
[1]		[2]	[3]	[4]	[5]	[6]	[7]
FERC-jurisdictional							
CAISO	[a]	Order 1000	10	Projects	10	Yes	Gates-Gregg, Imperial Valley, Sycamore-Peñasquitos,Delaney-Colorado River, Estrella, Wheeler Ridge Junction, Suncrest, Spring, Harry Allen-Eldorado, Miguel
ISO-NE	[b]	Order 1000	0	Solutions	0	No	n/a
MISO	[c]	Order 1000	2	Projects	2	Yes	Duff-Coleman, Hartburg-Sabine
NYISO	[d]	Order 1000	2	Solutions	3	No	Western New York, AC Transmission Public Policy
PJM	[e]	Order 1000	16	Solutions	139	Yes*	Thorofare, Artificial Island, ApSouth Market Efficiency
SPP	[f]	Order 1000	1	Projects	1	No	Walkemeyer-N. Liberal
Total FERC-jurisdictional	**[g]**		**31**		**155**		
Other U.S.							
ERCOT	[h]	State Directed	1	Projects	186	No	CREZ (4), Houston Import (1)
Canadian							
AESO	[i]	2010 Amendments to T-Reg	1	Projects	1	Yes	Fort McMurray West
IESO	[j]	Ontario Energy Board	2	Projects	2	No	East-West Tie Line, Wataynikaneyap Project

Notes:

* Only Artificial Island included cost containment.

[4]: Under the competitive "projects" process, the transmission planning region identifies regional transmission needs and selects the more efficient or cost-effective transmission solutions to meet those needs. The transmission planning region then solicits proposals from qualified transmission developers and chooses from among the developers and designates a selected transmission developer as eligible to use the regional cost allocation method to develop the selected transmission project. Under the "sponsor" process, the transmission planning region identifies regional transmission needs. Then, qualified transmission developers may propose transmission projects to meet those identified regional transmission needs. The transmission planning regions selects the more efficient or costeffective transmission solution to meet each identified regional transmission need, which can be a solution proposed by a transmission developer or one that the transmission planning region designed itself.

[2][i]: In November 2009, Alberta passed the Electric Statutes Amendment Act (also known as Bill 50), which designated four transmission projects as Critical Transmission Infrastructure (CTI) and provided the Alberta Cabinet the authority to designate future projects as CTI. Following this in 2010, an amendment to Alberta's Transmission Regulation (T-Reg) was passed, mandating the AESO develop a competitive process for certain transmission projects, including those designated as CTI. In 2012, the Electric Utilities Amendment Act (also known as Bill 8) was passed, which removed the Cabinet's authority to designate CTI and also required projects to obtain AUC approval; Per the AESO's mandate and subsequent legislative developments (Bill 8), AESO is responsible for running its competitive processes, and the selected projects are required to obtain AUC approval.

For more details see: https://www.aeso.ca/assets/Uploads/Competitive-Process-Recommendation-Paper-Final.pdf
https://www.energy.alberta.ca/AU/electricity/AboutElec/Pages/Transmission.aspx
http://www.energyregulationquarterly.ca/articles/competition-in-electricity-transmission-two-canadian-experiments#sthash.YwmqCqGq.FDZeXnxS.dpbs

[2][j]: The Ontario Energy Board (OEB) first developed the Framework for Transmission Project Development Plans (EB-2010-0059) in August 2010. In 2011, Ontario's Ministry of Energy recommended the OEB engage its previously developed transmission development designation policy to "select the most qualified and cost-effective transmission company to develop the East-West Tie".

For more details see: http://www.energyregulationquarterly.ca/articles/competition-in-electricity-transmission-two-canadian-experiments#sthash.YwmqCqGq.pBATi6ye.dpbs

Sources:

[4][a],[c]-[f]: FERC 2017 Transmission Metrics Staff Report, p8. The Project model is is referred to as the Competitive Bidding model and the Solution model is referred to as Sponsorship model.

[4][h]: ERCOT: The Texas Competitive Renewable Energy Zone Process, September 2017, p17-18.

Table 6: Competitive Transmission Projects Summary

ISO/RTO		Project	Year of Decision	Selected Developer	Award to Incumbent?	Cost Containment?	ISO's Planning Estimate/Lowest Cost Proposal from Incumbent	Cost of Selected Proposal (incl. any non-competitive portion) ($Million)	Updated Cost of Project ($Million) (Current Estimate)	Selected Proposal % Change vs. ISO or Incumbent Estimated Cost
[1]		[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
CAISO	[a]	Gates-Gregg	2013	PG&E/MidAmerican w/ Citizen Energy	Yes	No	$145	$130	n/a	-10%
	[b]	Imperial Valley	2013	Imperial Irrigation District	No*	Yes	$25	$14	n/a	-43%
	[c]	Sycamore-Peñasquitos 230kv Transmission Line Project	2014	SDG&E w/ Citizen Energy	Yes	No	$221	$108	n/a	-51%
	[d]	Delaney-Colorado River Project	2015	DCR Transmission	No	Yes	$300	$280	n/a	-7%
	[e]	Estrella Substation Project	2015	NextEra	No	Yes	$45	$20	n/a	-56%
	[f]	Wheeler Ridge Junction	2015	PG&E	Yes	No	$140	$60	$32	-57%
	[g]	Suncrest	2015	NextEra	No	Yes	$75	$37	n/a	-50%
	[h]	Spring Substation	2015	PG&E	Yes	No	$45	$28	$21	-38%
	[i]	Harry Allen-Eldorado Project	2016	Desert Link	No	Yes	$144	$133	n/a	-8%
	[j]	Miguel	2014	SDG&E	Yes	n/a	$40	n/a	$58	n/a
MISO	[k]	Duff-Coleman 345 kV	2016	LS Power w/ Big Rivers	No	Yes	$59	$50	n/a	-15%
	[l]	Hartburg-Sabine Junction 500 kV	2018	NextEra	No	Yes	$122	$104	n/a	-15%
NYISO	[m]	Western NY Public Policy Transmission	2017	NextEra Energy Transmission	No	No	$232**	$181	n/a	-22%
	[n]	AC Transmission Public Policy Segment A	2019	North America Transmission and NYPA	No	n/a	n/a	$750	n/a	n/a
	[o]	AC Transmission Public Policy Segment B	2019	Niagara Mohawk and New York Transco	Yes	n/a	n/a	$479	n/a	n/a
PJM	[p]	Artificial Island Project	2015	LS Power (w/ PSEG incumbent substation work)	No	Yes	$692	263 - $283	$280	-61%
	[q]	AP South Market Efficiency	2016	Transource, BGE, and Allegheny Power	No****	No	n/a	$320	$328	n/a
	[r]	Thorofare Project	2015	Transource	No****	No	n/a	$60	$72	n/a
	[s]	136 Projects Awarded to Incumbents (132 upgrades)	2014-2017	Various	Yes	n/a	n/a	n/a	n/a	n/a
SPP	[t]	North Liberal – Walkemeyer 115 kV	2016	MKEC	Yes	No	$17	$8	Cancelled	-50%
US Total	[u]						$2,030	$1,246	$790	**-39%**
AESO	[v]	Fort McMurray West 500 kV Transmission Project	2014	Alberta PowerLine Limited Partnership	Yes	Yes	$1,800	$1,430	$1,614	-21%
IESO	[w]	East West Tie Line	2013	NextBridge Infrastructure	No	No	$928***	$439	$777	-53%
	[x]	Wataynikaneyap Power	2015	Fortis	No	n/a	n/a	n/a	n/a	n/a
Total	**[y]**						$4,758	$3,115	$3,182	**-35%**

Notes:

*While Imperial Irrigation District (the selected developer of the Imperial Valley project) is the incumbent in the Imperial Valley Region, it is not a CAISO PTO and thus not an incumbent within the CAISO footprint.

**NYISO did not develop an ISO planning estimate for this project, the shown estimate instead reflects the lowest cost proposal from incumbent.

***IESO did not develop an ISO planning estimate for this project, the shown estimate instead reflects the cost developed by incumbent prior to competition.

**** Transource is a joint venture between AEP and Great Plains Energy.

[u]: Does not include NYISO costs. See also tab NYISO Competitive Projects.

[7][w]: Reflects Incumbent Proposal with comparable design as Selected Proposal See tab Ontario Competitive Projects for more details.

[8][9],[y]: Does not include Miguel Project and Wataynikaneyap Power Project.

[10][a]-[j]: We compare the cost of the selected proposal to the CAISO's upper end estimate as it is generally more consistent with the TO-prepared estimates as submitted to the CPUC. See Table 18.

[10][y]: Does not include Miguel Project and Wataynikaneyap Power Project. Selected proposal cost for Artificial Island Project taken as the average of selected proposal cost range.

Table 7: MISO Competitive Project Summary

Project	Year of Decision	Selected Developer	Incumbent?	MISO's Planning Estimate ($million)	Selected Proposal Cost ($million)	Selected Proposal Cost % Change vs. MISO's Planning Estimate	Cost Containment	Key Selection Factors
[1]	[2]	[3]	[4]	[5]	[6]	[7]=[6]/[5]-1	[8]	[9]
Duff-Coleman 345 kV [a]	2016	LS Power w/ Big Rivers	No	$58.9	$49.8	-15%	Yes	Selection based on "firm rate base cap" and low ATRR estimate.
Hartburg-Sabine Junction 500 kV [b]	2018	NextEra	No	$122.4	$103.9	-15%	Yes	Selection based largely on cost caps and cost containments, including forgoing of AFUDC and CWIP.

Notes:

MISO's 2017 quarterly update indicates the current cost estimate of the project at $53.8 million, which is equivalent to the cost of selected proposal inflated to in-service year dollars.

Sources:

Year of project selection, selected proposal, planning developer, and selected proposal cost reported in MISO selection reports.

Cost Containment for Duff-Coleman in Selected Developer Agreement by and between Republic Transmission, LLC and Midcontinent Independent System Operator, Inc., Original Sheet No. 20

[6]: NextEra estimated the total implementation cost of the project to be $114.8 million. MISO noted that the equivalent implementation cost would be $103.9 million in 2018 dollars.

Table 8: SPP Competitive Project Summary

Project		Year of Decision	Selected Developer	Incumbent?	SPP's Planning Estimate ($million)	Selected Proposal Cost (2015 $million)	% Change of selected proposal cost vs. SPP's Planning Estimate	Cost Containment	Key Selection Factors	Other Notes
[1]		[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
North Liberal – Walkemeyer 115 kV	[a]	2016	MKEC	Yes	$16.8	$8.3	-50%	No	Consistently strong application across all metrics.	-Several competing proposals offered at lower costs than SPP's Planning Estimate for the Project. -Project has been cancelled.

Sources:

Year of project selection, and selected proposal cost data reported in SPP IEP Recommendation Report for the project. Planning estimate reported in SPP RFP.

Selected proposal information as reported in SPP issued NTC for the project (SPP-NTC-200385).

Cost containment from IEP Transmission Provider Internal Report for RFP000001, pg. 31

Table 9: CAISO Competitive Projects Summary

Project	Year of Decision	Selected Developer	Incumbent?	Lower Bound of CAISO's Planning Estimate Range ($million)	Upper Bound of CAISO's Planning Estimate Range ($million)	Midpoint of CAISO's Planning Estimate Range	Selected Proposal Cost ($million)	Updated Cost of Project ($million) (current estimate)	Selected Proposal Cost % Change vs. CAISO's Lower Bound Estimate	Selected Proposal Cost % Change vs. CAISO's Upper Bound Estimate	Cost Containment	Key Selection Factors	Other Notes
[1]	[2]	[3]	[4]	[5]	[6]	[7]=([5]+[6])/2)	[8]	[9]	[10]=[8]/[5]	[11]=[8]/[6]	[12]	[13]	[14]
Gates-Gregg [a]	2013	PG&E/MidAmerican w/ Citizen Energy	Yes	$115	$145	$130	$130	n/a	13%	-10%	No	Has existing ROW that could contribute to project	Project is on hold
Imperial Valley [b]	2013	Imperial Irrigation District	Yes	$25	$25	$25	$14	n/a	-43%	-43%	Yes	Substantially lower cost cap than other proposal	Project has been cancelled
Sycamore-Peñasquitos 230kv Transmission Line Project [c]	2014	SDG&E w/ Citizen Energy	Yes	$111	$221	$166	$108	n/a	-2%	-51%	No	Has existing ROW and franchise rights that could contribute to the project	
Delaney-Colorado River Project [d]	2015	DCR Transmission	No	$300	$300	$300	$280	n/a	-7%	-7%	Yes	Lowest projected revenue requirement, binding cost containment on capital costs and partial containment of ROE	
Estrella Substation Project [e]	2015	NextEra	No	$35	$45	$40	$20	n/a	-43%	-56%	Yes	Reasonable cost cap and lowest interconnection costs	
Wheeler Ridge Junction [f]	2015	PG&E	Yes	$90	$140	$115	$60	$32	-33%	-57%	No	PG&E's maintenance headquarters is near by	
Suncrest [g]	2015	NextEra	No	$50	$75	$63	$37	n/a	-25%	-50%	Yes	Most robust cost containment; materially lower capital costs.	
Spring Substation [h]	2015	PG&E	Yes	$35	$45	$40	$28	$21	-20%	-38%	No		
Harry Allen-Eldorado Project [i]	2016	Desert Link	No	$144	$144	$144	$133	n/a	-8%	-8%	Yes	Strongest binding cost containment. Robust capital/construction costs and ROE caps	
Miguel [j]	2014	SDG&E	Yes	$30	$40	$35	n/a	$58		n/a	Unknown	Only one qualified project sponsor	Project is in service
Total [k]				**$935**	**$1,180**	**$1,058**	**$811**	**$110**	**-10%**	**-29%**			

Sources:

[2],[3],[12]: Year of project selections,selected developer, and cost containment based on CAISO selection reports, with the exception of the Miguel project. Miguel's selection year and selected proposal per CAISO market notice.

[5],[6]: Estimates reported in selection reports and CAISO functional specification documents.

[8]: Selected proposal cost estimates for rows [a], [e], and [g] from Approved Project Sponsor Agreements. Selected proposal cost estimates for rows [b] and [i] from CAISO selection reports. Selected proposal cost estimates for rows [f] and [h] from PG&E's response to data request CPUC-PGE-053 in FERC Docket No. ER16-2320-002. Selected proposal cost estimates for row [c] from its Approved Project Sponsor Agreement and its CPUC Certificate of Public Convenience and Necessity decision filing. Selected proposal cost estimate for row [d] from its CPUC Certificate of Public Convenience and Necessity application.

[9]: Updated cost estimates for row [j] from SDG&E's TO4 Cycle 5 Volume 2 filing. Updated cost estimates for rows [f] and [h] from PG&E's response to data request CPUC-PGE-053 in FERC Docket No. ER16-2320-002.

[c]: Competitive solicitation originally selected overhead design but was subsequently changed to an underground design after project was awarded to selected developer.

Table 10: Selected PJM Competitive Projects Summary

Project		Year of Decision	Selected Developer	Incumbent?	Selected Proposal Cost ($million)	Lowest-Cost Proposal Cost from Incumbent ($million)	Updated Project Cost ($million) (Current Estimate)	Updated Project Cost % Change vs. Incumbent Proposal Cost	Cost Containment	Key Selection Factors	Other Notes
[1]		[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Artificial Island Project	[a]	2015	LS Power (w/ PSEG incumbent substation work)	No	$263 - $283 (Total Cost of Selected Proposal, Competitive + Incumbent Portion)	$692	$280	-60%	Yes	Per PJM Selection Report, LS Power's Selected Proposal provided the strongest cost containment offer.	-Initially, PSE&G proposed 14 (of 26) solutions for Aritficial Island, with costs ranging from a low of $692 million to a high of $1.5 billion. Of the 26 proposed projects, only two satisfied the performance criteria specified, so according to the selection white paper "PJM undertook additional engineering review to identify the most effective solution to stated needs, taking into consideration the elements of submitted proposals." -PSE&G ultimately provided a proposal with an estimated project cost of $277-$285 million, with $221 million in cost containment for specific work. However, this proposed project came only after PJM had analyzed the most effective components of the 26 initial proposals and applied its findings to the existing proposals. -LS Power's selected proposal cost contains a $146 million cost containment for their portion of the project. Adding incumbent substation work to LS Power's competitive portion increases the total cost of the solution to the $263 million to $283 million range. LS Power's cost containment contained fewer exceptions than PSE&G's cost containment, which led to the recommendation of LS Power's project.
AP South Market Efficiency	[b]	2016	Transource, BGE, and Allegheny Power	No	$320	n/a	$328	n/a	No	15-year congestion and load payment savings estimate of $619 million and $269 million.	
Thorofare Project	[c]	2015	Transource	No*	$60	n/a	$72	n/a	No	n/a	
136 Incumbent Projects (132 upgrades)	[d]	2014-2017	Various	n/a	n/a	n/a	$955	n/a	n/a	n/a	

Notes:

Summary only includes projects wherein PJM selected Non-Incumbent developers.

[a]: Illustrated cost reduction in [8] for Artificial Island Project based on comparison of LS Power's current project cost and Incumbent PSEG's lowest cost project initially proposed.

[c]: *The Selected Developer for the Thorofare Project is Transource, which is a joint venture between AEP and Great Plains.

Sources:

[a][2]-[6]: Year of project selection, selected developer, selected proposal cost, incumbent proposal cost, and total project capital cost estimates from Artificial Island Project Recommendation White Paper.

[a][7]: Updated project cost estimates from Artificial Island White Paper, dated April 2017.

[a][9]: Designated Entity Agreement between PJM Interconnectioin, LLC and Northeast Transmission Development, Schedule E, pg. 25.

[b][2]-[6]: Year of project selection, selected developer, and selected proposal cost from the August 2016 TEAC Recommendations to the PJM Board.

[b][7],[c][7]: Updated Project costs from the PJM Transmission Construction Database.

[b][9]: Definition of Schedule E on PJM Manual 14F: Competitive Planning Process Section 8: Project Evaluation, pg. 40

[c][2]-[5]: Transmission Expansion Advisory Committee Reliability Analysis Update, September 10, 2015, available at: https://www.pjm.com/-/media/committees-groups/committees/teac/20150910/20150910-teac-reliability-analysis-update.ashx

[d]: Number of projects comes from Craig Glazer's 2018 WIRES meeting presentation. The value of these projects is calculated from subtracting the $663 million total cost of the Artificial Island, ApSouth Market Efficiency, and Thorofare projects from the $1,615 million in projects approved that were eligible for competition, presented in the PJM TEAC's 2017 Project Statistics presentation.

Summary of Initial Artificial Island Competitive Proposals

Project ID	Incumbent?	Proposal Sponsor	Proposal Sponsor Estimated Cost ($million)
P2013_1-7A	Yes	PSE&G	$1,371
P2013_1-7B	Yes	PSE&G	$1,372
P2013_1-7C	Yes	PSE&G	$1,372
P2013_1-7D	Yes	PSE&G	$831
P2013_1-7E	Yes	PSE&G	$692
P2013_1-7F	Yes	PSE&G	$879
P2013_1-7G	Yes	PSE&G	$1,034
P2013_1-7H	Yes	PSE&G	$1,177
P2013_1-7I	Yes	PSE&G	$1,353
P2013_1-7J	Yes	PSE&G	$915
P2013_1-7K	Yes	PSE&G	$1,066
P2013_1-7L	Yes	PSE&G	$1,250
P2013_1-7M	Yes	PSE&G	$1,548
P2013_1-7N	Yes	PSE&G	$1,289
P2013_1-1A	No	Virginia Electric and Power Company	$133
P2013_1-1B	No	Virginia Electric and Power Company	$126
P2013_1-1C	No	Virginia Electric and Power Company	$202
P2013_1-2A	No	Transource	$213 - $269
P2013_1-2B	No	Transource	$165 - $208
P2013_1-2C	No	Transource	$123 - $156
P2013_1-2D	No	Transource	$788 - $994
P2013_1-3A	No	First Energy	$410.7 (Only FirstEnergy portion)
P2013_1-4A	No	PHI Exelon	$475
P2013_1-5A	No	LS Power	$116.3 - $148.3
P2013_1-5B	No	LS Power	$170
P2013_1-6A	No	Atlantic Wind	$1,012

Source:
Artificial Island Project Recommendation White Paper
Accessed at: http://www.pjm.com/~/media/committees-groups/committees/teac/postings/artificial-island-project-recommendation.ashx

Table 11: NYISO Competitive Project Summary

Project		Year of Decision	Selected Developer	Incumbent?	Lowest-Cost Proposal from Incumbent ($million)	Selected Proposal Cost Estimate (2017 $million)	Cost Containment	Selected Proposal Cost % Change vs. Incumbent Proposal
[1]		[2]	[3]	[4]	[5]	[6]	[7]	[8]
Western NY Public Policy Transmission	[a]	2017	NextEra	No	$232	$181	No	-22%
AC Transmission Public Policy Segment A	[b]	2019	North America Transmission and NYPA	No	n/a	$750	n/a	n/a
AC Transmission Public Policy Segment B	[c]	2019	Niagara Mohawk and New York Transco	Yes	n/a	$479	n/a	n/a

Notes:

NYISO relied on the overall benefits of the project, in addition to cost considerations, in making its final selection of the selected proposal. With regard to benefits, NYISO estimated the selected proposal's production cost savings at $274 million, and that of the lowest Incumbent Proposal at $229 million (In 2017 dollars). Overall, the Selected Proposal provided greater production cost savings at lower capital cost compared to the Incumbent Proposal.

Sources:

[a][2]-[6]: Western New York Public Policy Planning Report.

[a][7]: No cost cap included in NextEra's proposal.

[b],[c]: AC Transmission Public Policy Transmission Plan Report, April 8, 2019.

Table 12: NYISO Competitive Project Experience: Additional Production Cost Savings of Western NY Public Policy Transmission

Competitive Process Participant		Capital Cost Estimate (2017 $million)	Production Cost Savings (2017 $million)	Net Customer Costs (2017 $million)
[1]		[2]	[3]	[4]=[2]-[3]
Selected Proposal (NextEra; Non-Incumbent)	[a]	$181	$274	-$93
Best Incumbent Proposal	[b]	$232	$229	$3
<u>NextEra Benefit vs. Best Incumbent Proposal</u>				**<u>Total Net Customer Savings</u>**
Net Customer Cost Advantage of Selected Proposal	[c]			$96
% Advantage	[d]			41%

Notes:

[c]: Difference between Net Customer Costs of Selected Proposal and Best Incumbent Proposal.

[d]: Calculated as total cost benefit advantage of selected proposal cost divided by capital cost estimate of Best Incumbent Proposal.

Sources:

Western New York Public Policy Planning Report

Table 13: AESO Competitive Project Summary

Project	Year of Decision	Selected Developer	Incumbent?	AESO Planning Estimate +/- 50% (CAD million)	Selected Proposal Cost (2019 CAD million)	Updated Cost Estimate (current estimate, 2020 CAD million)	Selected Proposal Estimated Cost % Change Vs. AESO Planning Estimate	Cost Containment	Key Selection Factors
[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]=[6]/[5]-1	[9]	[10]
Fort McMurray West 500 kV Transmission Project [a]	2014	Alberta PowerLine Limited Partnership	Hybrid	$1,800	$1,430	$1,614	-21%	Yes	Cost Savings was the key selection factor. AESO noted that the Fort McMurray West competition cost savings for Alberta ratepayers were "conservatively estimated to be over $400 million".

Notes:

[a]: Cost reduction in [8] evaluated as Selected Proposal Cost vs. AESO's Planning Estimate since AESO's Selection Report and Recent CEO Presentation entitled "Competitive Electricity Market & Emerging Transmission Expansion Policies" indicates that Project is a "Fixed Price Contract" with cost changes permitted if in predetermined Agreements. The increase in updated project cost shown is due to change in project route from the East Route to the longer West Route, per approval by the regulator. The new West Route was not pre-defined at the time of Project award. Additionally, the updated cost reflects allowed inflation adjustments.

Sources:

[1]-[6],[8]: https://www.aeso.ca/grid/competitive-process/fort-mcmurray-west-500-kv-transmission-project/

[7]: http://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2017/21030-D02-2017.pdf

[9]: An Innovative Hybrid PPP for Electric Transmission Infrastructure in Alberta, A Case Study, pg. 8, footnote 20

Table 14: Ontario Competitive Project Summary

Project		Year of Decision	Selected Developer	Incumbent?	Incumbent Proposal with Comparable Design as Selected Proposal (2020 CAD million) *Inflation Reflected*	Selected Proposal Cost (2012 CAD million) *Inflation Reflected*	Updated Cost Estimate (current estimate, 2020 CAD million)	Updated Cost Estimate % Change relative to Incumbent Proposal with Comparable Design as Selected Proposal	Cost Containment	Other Notes
[1]		[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
East West Tie Line	[a]	2013	NextBridge Infrastructure	No	$928	$439	$777	-16%	No	The cost of Incumbent Proposal with comparable design as the Selected Proposal was $724.7 million (2010 CAD). When inflated to in-service year (2020) CAD, this value increases to $928 million. The updated cost estimate of the selected proposal shown is reflective of development cost, construction cost and inflation adjustments.
Wataynikaneyap Power	[b]	2015	Fortis	No	n/a	n/a	n/a	n/a	n/a	-Fortis owns 49% Wataynikaneyap Power, in conjunction with 22 First Nations communities -Joint venture was developed to connect remote First Nations communities, currently powered by diesel generators, to the electric grid

Notes:

[a][5]-1: In 2010, Hydro One (incumbent) developed 6 potential designs for the East West Tie Line project. Cost estimates for the six options ranged from $439 million to $1216 million. The double circuit option, entitled "L1",with a cost estimate of $724.7 million (in 2010 CAD) is the most comparable option in design and line length to NextBridge's Selected Proposal project from the competitive solicition of 2013 for the East West Tie Line. Because these six Hydro One options were developed prior to the development of the competitive procurement process for the project, the benefit of competition is assessed as a comparison of the Selected Proposal cost relative to the Hydro One's most comparable design option cost, when Hydro One first proposed a solution for the project.

[a][5]: For comparison with the Updated Cost Estimate of the Selected Proposal, cost of Hydro One's comparable option is adjusted to reflect an assumed annual inflation of 2.5%.

[a][6]: Adjusted from $419.06MM estimated cost at designation to reflect revised 2020 in-service date.

[a][7]: Reflects CAD$104 million increase due to new scope requirements and CAD$122 million increase due to development phase project refinements.

[a][2]-[4],[6]-[7],[10]: NextBridge Application for Leave to Construct, accessed at: http://www.rds.oeb.ca/HPECMWebDrawer/Record?q=CaseNumber=EB-2017-0182+And+WebDocumentType:%22Application%20and%20Evidence%22&sortBy=recRegisteredOn-&pageSize=400.

[a][9]: No cost cap included in NextBridge's proposal.

Table 15: PJM Cost Escalations Breakdown
for Projects with available Initial and Latest Cost Estimates
(2014 - 2017 In Service or Under-Construction Baseline & Network Upgrade Projects)

	Initial TO Cost Estimate *(provided at time of PJM Advisory Committee recommendation)*	Latest TO Cost Estimate *(reported by PJM Cost Allocation Tracking)*	Cost Escalation
	[1]	[2]	[3]=[2]/[1]-1
2014	$822	$971	18%
2015	$1,722	$2,124	23%
2016	$768	$940	22%
2017	$382	$485	27%
Total	**$3,695**	**$4,520**	**22%**

Notes:

Table reflects only projects with reported intial cost data *and* latest cost data.

Projects are categorized into years based on PJM provided "DisplayServiceDate" variable in PJM Transmission Construction Status Database.

Supplemental and TO Initiated projects are only notified to TEAC but standard reporting of costs are not tracked by PJM's Transmission Construction Status Database, so they are not reflected in this data.

[3]: Variance percentages are estimated for all 2014-2017 In-service / Under-Construction Baseline Reliability and Network projects reported by PJM to have experienced a cost change (i.e., projects that are reported to have experienced either a cost escalation or an underrun); Approximately 28% of 2014-2017 In-Service/Under-Construction Baseline and Network Upgrade Projects are reported to have expereinced cost changes since Project Approval by PJM's TEAC Recommendation committee. Other 72% of PJM's reported projects are reported with the exact same initial and latest estimates in PJM's Transmission Construction Status Database. It is unclear whether these reported latest estimated costs in PJM's database are appropiately reflective of actual cost changes in Projects' cost estimates, therefore they have been excluded from this cost variance calculation.

Sources:

[1]: Initial cost estimates from 2014-2017 PJM TEAC Staff Whitepapers
http://www.pjm.com/committees-and-groups/committees/teac.aspx

[2]: Latest Cost Estimates from PJM Transmission Construction Status Database
http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx

Table 16: Historical Cost Escalations for Completed SPP Transmission Projects ($million)

		Initial Cost Estimate (submitted to SPP by TO)	Latest Cost Estimate Tracked by SPP	Cost Escalation
		[1]	[2]	[3]=[2]/[1]-1
SPP Balanced Portfolio	[a]	$691	$831	20%
SPP Priority Projects	[b]	$1,145	$1,349	18%
ITP Portfolio Projects with Final Cost Estimates (2012 to 2017)	[c]	$192	$211	10%
Total	[d]	**$2,028**	**$2,391**	**18%**

Notes:

[1]: Initial Cost Estimates are E&C cost estimates provided by TO's upon projects first inclusion in the SPP Quarterly Project Tracking Report.

[2]: Final Cost Estimates are E&C cost estimates provided by TO's upon projects completion, in the SPP Quarterly Project Tracking Report.

[b]: Note that in October 2010, 6 months after the projects initial approval, the Board approved a $271 million dollar cost increase to the projects.

[c]: $1 billion of in-service SPP ITP projects do not provide final costs in the Quarterly Project Tracking Report, and thus cannot be used to calculate cost variances, so they are excluded from this row.

Sources:

[a]: Balanced Portfolio data comes from the 2017 Q2 SPP Quarterly Project Tracking Report.

[b]: Priority Projects data comes from the 2017 Q4 SPP Quarterly Project Tracking Report.

[c]: ITP Portfolio data comes from the 2019 Q1 SPP Quarterly Project Tracking Report, Appendix 1.

Table 17: MISO Historical Cost Escalations for Base Reliability, MVP, and MEP Facilities for which Initial and In-Service/Under-Construction Cost Estimates are Available

(2015-2017 In-Service, 2018 In-Service or Under-Construction)

Quarter	Number of Facilities	TO Estimate Provided to MISO After Approval ($million)	TO Latest Cost Estimate Provided to MISO ($million)	Cost Escalation
	[1]	[2]	[3]	[4]=[3]/[2]-1
2015Q1	23	$769	$707	-8%
2015Q2	25	$909	$935	3%
2015Q3	7	$33	$29	-12%
2015Q4	0	$0	$0	-
2016Q1	6	$27	$48	75%
2016Q2	45	$291	$304	4%
2016Q3	18	$231	$289	25%
2016Q4	41	$702	$901	28%
2017Q1	3	$6	$8	29%
2017Q2	16	$196	$255	30%
2017Q3	30	$422	$353	-17%
2017Q4	13	$155	$207	33%
2018Q1	77	$2,217	$3,017	36%
Total	**304**	**$5,960**	**$7,053**	**18%**

Notes:
[2]: Initial cost estimate submitted by TO.
[3]: TO facility cost estimate after the project is in-service or has a planned status of under-construction.
Sources:
Cost estimates shown are for in-service & under construction Base Reliability, MVP, and MEP facilities, as reported in MISO's MTEP Appendix A Status Trackers.

Table 18: Historical Cost Escalations for CAISO Transmission Projects

Project		TO Cost Estimate submitted to CAISO/CPUC ($million)	Lower End of CAISO Estimate ($million)	Upper End of CAISO Estimate ($million)	Submitted Cost Estimate relative to Upper End of CAISO Estimate (% change)	Estimated Final Cost ($million)	Estimated Final Cost relative to TO's CAISO/CPUC Submitted Cost (% change)	Estimated Final Cost relative to CAISO Upper End Estimate (% change)
[1]		[2]	[3]	[4]	[5]=[2]/[4]-1	[6]	[7]=[6]/[2]-1	[8]=[6]/[4]-1
Wheeler Ridge Junction 230kV Substation	[a]	$155	$90	$140	11%	$151	-3%	8%
Spring 230kV Substation	[b]	$48	$35	$45	7%	$98	104%	118%
Estrella 230kV Substation	[c]	$34	$35	$45	-24%	$96	179%	113%
Martin 230kV Bus Extension	[d]	$129	$85	$129	0%	$285	121%	121%
Midway-Andrew 230kV Project	[e]	$154	$120	$150	2%	$198	29%	32%
Lockeford-Lodi Area 230kV Development	[f]	$103	$80	$105	-2%	$163	58%	55%
Oro Loma 70kV Reinforcement	[g]	$46	$46	$46	0%	$30	-34%	-34%
ECO Substation	[h]	$273	-	-	-	$410	50%	-
New TL ES-Ash #2	[i]	$22	-	< $50M	-	$5	-78%	-
IV West Generator Interconnection (Q608)	[j]	$2	-	-	-	$1	-47%	-
Talega-Add Synchronous Condensers	[k]	$64	$58	$72	-11%	$81	26%	12%
Shunt Reactor on Suncrest 500kV Bus	[l]	$11	-	-	-	$10	-10%	-
Pio Pico Energy Ctr. Gen. Interconnect	[m]	$9	-	-	-	$10	2%	-
Relocate South Bay Substation	[n]	$129	$129	$129	0%	$121	-7%	-6%
Talega Bank 50 Replacement	[o]	$6	$5	$6	-8%	$2	-61%	-64%
TL13821 and TL13828-Fanita Junction Enhancement	[p]	$41	-	<50M	-	$35	-15%	-
Encina Bank 61	[q]	$11	-	<50M	-	$8	-29%	-
Tehachapi	[r]	$1,800	-	-	-	$2,350	31%	-
Total	[s]	**$3,037**	**$683**	**$867**	**0%***	**$4,053**	**33%**	**41%****

Notes:

These Projects are not the complete universe of CAISO projects. CAISO typically reports a high and low estimate. The table reports CAISO's high estimate as it is generally more consistent with the TO-prepared estimates as submitted to the CPUC.
*Percentages exclude projects with no specific CAISO estimates.
**Percentages exclude projects with no specific CAISO estimates. <50M is not considered a specific estimate.
[2][a]-[g]: PG&E cost estimate is cost information submitted to CAISO at time of project review. These values differ from the CAISO approved cost presented in its TPP.
[6][a]-[g]: PG&E estimated final cost is project forecasted cost at completion and excludes contingency costs, but includes risk.
[a],[b]: These projects have competitive and noncompetitive portions, both of which are represented in the values presented here. Note that in both cases, noncompetitive portions have experienced escalations, while competitive portions have experienced underruns.
[2][h]-[q]: SDG&E Initial Cost Estimate is the estimated cost of the project as of its first inclusion on AB970.
[6][h]-[q]: SDG&E Final Cost is the FERC ratebase dollars for the project.
[2][r]: The initial cost estimate is the cost first approved by CAISO in 2007 transmission plan
[8]: We compare the estimated final cost to the CAISO's upper end estimate as it is generally more consistent with the TO-prepared estimates as submitted to the CPUC, as shown above.
Measuring cost escalations relative to the CAISO's lower end estimate would yield higher percentage increases.
Sources:
[a]-[g]: Exhibit PUC-0015 in FERC Docket No. ER16-2320-000; excludes Northern Fresno 115 kV Reinforcement because the project experienced significant scope changes.
[h]-[q]: SDG&E Responses to data requests issued in FERC No. EL17-45. Only projects approved by CAISO or the CPUC and CAISO were included in this sample. Additionally, only projects with initial and final cost estimates were included in this sample.
[r]: Initial cost data from 2016 - 2017 CAISO Draft Transmission Plan Stakeholder Meeting, page 13 comment 2b. Latest Cost Estimate reported in SCE's 2016 Q4 Quarterly Report.

Table 19: Historical Escalations for ISO-NE Transmission Projects

Project		Intial TO Cost Estimate ($million)	Final TO Cost Estimate ($million)	Cost Escalation
[1]		[2]	[3]	[4]=[3]/[2]-1
Scobie-Tewksbury	[a]	$123	$120	-2%
Wakefield-Woburn	[b]	$107	$137	28%
Mystic Woburn	[c]	$75	$82	9%
Stoughton Cable Project (Phase I & II)	[d]	$213	$317	49%
Southwest Connecticut	[e]	$690	$1,415	105%
Norwalk Reliability	[f]	$128	$234	83%
Worcester Reliability	[g]	$7	$33	377%
Long Term Lower SEMA	[h]	$107	$105	-2%
Millstone DCT elimination	[i]	$22	$39	76%
NEEWS – Greater Springfield	[j]	$350	$759	117%
NEEWS – Rhode Island Reliability	[k]	$150	$315	110%
Merrimack Valley / North Shore Project	[l]	$43	$62	45%
NEEWS - Interstate Reliability	[m]	$400	$542	35%
Stamford Reliability	[n]	$49	$42	-15%
Total	**[o]**	**$2,464**	**$4,201**	**70%**

Notes:
[o]= sum of [a]-[n]
[a]-[c]: ISO NE Regional System Plan(RSP) Pool Transmission Facility estimated costs.
[d]-[n]:Based on Transmission Cost Allocation(TCA) filing cost estimate and RSP Project listing's estimate.

Sources:
[a]-[c]: ISO NE Final RSP 18 Project List - March 2018 https://www.iso-ne.com/system-planning/system-plans-studies/rsp/
[d]-[n]:New Hampshire Transmission Greater Boston Cost Comparison January 2015 Presentation.

Table 20: Estimated Savings from Competitive Transmission Planning Processes to Date

RTO		ISO or Incumbent Estimated Cost of Competitive Projects ($million)	Selected Proposal Estimated Cost of Competitive Projects ($million)	Average % Customer Cost Savings for Competitive Projects as Proposed	Average Historical Escalation of Transmission Projects (%)	Expected Cost if Competitive Projects were not subject to Competition ($million)	Potential $ Savings from Competition w/o proposal price escalation ($million)	Potential % Savings without Cost Escalation of Competitive Projects
		[1]	[2]	[3]=[2]/[1]-1	[4]	[5]=[1]x(1+[4])	[6]=[5]-[2]	[7]=[6]/[5]
CAISO	[a]	$1,180	$833	**29%**	41%	$1,667	$834	**50%**
ISO-NE	[b]	n/a	n/a	n/a	n/a	n/a	n/a	n/a
MISO	[c]	$181	$154	**15%**	18%	$215	$61	**28%**
NYISO	[d]	$232	$181	**22%**	n/a	$232	$51	**22%**
PJM	[e]	$692	$280	**60%**	22%	$847	$567	**67%**
SPP	[f]	$17	$8	**50%**	18%	$20	$11	**58%**

Notes:

[1]: Values for CAISO, MISO, and SPP are ISO estimates. Values for PJM and NYISO are incumbent costs. Values reflect 10 projects in CAISO, two projects in MISO, and one project in each of the other ISOs/RTOs.

[2]: Values are either the final cost estimate, latest cost estimate, or selected proposal cost estimate, depending on availability and relevance, taking precedence in that order.

[e]: PJM competitive project only reflects Aritificial Island Project.

[d][3]: NYISO relied on the overall benefits of the project, in addition to cost considerations, in making its final selection of the selected proposal. With regard to benefits, NYISO estimated the selected proposal's production cost savings at $274 million, and that of the lowest incumbent proposal at $229 million (In 2017 dollars). Overall, the Selected Proposal provided greater production cost savings at lower capital cost compared to the Incumbent proposal.

Sources:

[1],[2]: Please see tables 7 - 12.

[4]: Please see Tables 15, 16, 17, and 18.

Table 21: Approved Investment By RTO

Approved Transmission Investment ($million)		2012	2013	2014	2015	2016	2017	Total
CAISO (PG&E, SDG&E, and SCE only)	[a]	n/a	n/a	$1,611	$1,430	$1,002	n/a	$4,043
ISO-NE	[b]	$500	$1,400	$500	$800	$500	$2,100	$5,800
MISO	[c]	$1,125	$1,679	$1,843	$2,010	$1,498	$1,038	$9,193
NYISO	[d]	n/a	n/a	n/a	n/a	n/a	n/a	n/a
PJM	[e]	$1,354	$1,063	$3,643	$4,766	$3,623	$1,364	$15,811
SPP	[f]	$859	$369*	$1,816	$856	$939	$246**	$5,084
ERCOT	[g]	n/a	n/a	$218	$1,100	$2,000	$805	$4,123
Annual Total ($million)	[h]	**$3,837**	**$4,511**	**$9,630**	**$10,963**	**$9,562**	**$5,553**	**$44,056**

Notes:

[c]: There may be components of incomplete projects that have been placed in-service over these years, that are not reported by MISO in their in-service project list and therefore are not reported in these aggregates.

*Value as of December 3, 2013

**Value as of December 20, 2017

Sources:

[a]: Formal Complaint of California Public Utilities Commission, et. al. under EL17-45.

[b]: https://www.iso-ne.com/about/key-stats/transmission/

[c]:MISO Transmission Expansion Plan (MTEP) In-Service Project List as of 1/9/2018. Accessed on 4/10/2018. A current version of the List is available on the MISO website.

[e]: PJM Cost Allocation Database was used for costs for baseline; PJM Construction Cost Database was used for Network upgrades. Supplementary, and transmission owner initiated projects were excluded from these calculations.

Cost allocation database available at: http://www.pjm.com/planning/rtep-upgrades-status/cost-allocation-view

Construction Cost database available at:http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx

[f]: 2013-2018 SPP STEP Reports.

[g]: ERCOT Quick Facts sheets, 2015-2018, accessed at: http://www.ercot.com/news/presentations.

Table 22: Summary of Experience with Competition in UK

Region	Competitive Processes Completed	Summary of Completed Processes	Non-incumbent Awards	Cost-Containment	Key Notes
[1]	[2]	[3]	[4]	[5]	[6]
Great Britain	3	-The UK Office of Gas and Electricity Markets (OFGEM) has completed three competitive tender processes to connect up to 48 GW of offshore wind. -In tender Rounds 1 (November 2010) & 2 (March 2012), investors competed to own, finance and operate transmission assets, after construction for largely radial connections to the shore. -In Round 3 (February 2014), investors again competed to own, finance, and operate offshore transmission built by offshore wind developers, but were also provided the option to propose offers to construct transmission for offshore wind developers. Round 3 offshore wind farms were further from the shore, making transmission design more complex.	15	Fixed Revenue. *Ofgem determines allowed revenue based on benchmarks for allowed Cost of Capital*	On behalf of OFGEM, Cambridge Economic Policy Associates estimated NPV savings related to Rounds 1-3: *- Round 1 savings for nine projects ranging from £244 to £469 million* *- Round 2 savings for four OFTO projects ranging from £326 to £595 million* *- Round 3 savings for two OFTO projects ranging from £102 to £154 million* Types of Savings as a % of value of projects: *- Financial savings 8-11%* *-Operational savings 18-25%* Total net savings 23 - 34% -Rounds 1 & 2 were completed under a transitional regime, where only generation developers could build transmission systems. -Round 3 is occuring under the enduring regime, which allows for either generation developers or OFTOs to build transmission systems. -Rounds 4 & 5 have been initiated, but not completed.

Sources and Notes:

[3]: https://www.globaltransmission.info/archive.php?id=27887

[4]: https://www.ofgem.gov.uk/electricity/transmission-networks/offshore-transmission/offshore-transmission-tenders, non-incumbent awards identified by looking at each individual tender.

[6]: https://www.ofgem.gov.uk/publications-and-updates/evaluation-ofto-tender-round-2-and-3-benefits

Table 23: Cost Savings for Competitive Projects in CAISO and MISO

RTO	Scenario	Escalation Reflected		ISO or Incumbent Estimated Cost of Competitive Projects ($million)	Selected Proposal Estimated Cost of Competitive Projects ($million)	Average % Customer Cost Savings for Competitive Projects as Proposed	Average Historical Escalation of Transmission Projects (%)	Expected Cost if Competitive Projects were not subject to Competition ($million)	Potential $ Savings from Competition w/o proposal price escalation ($million)	Potential % Savings without Cost Escalation of Competitive Projects
		[1]		[2]	[3]=(1+[1])x[2]	[4]=[3]/[2]-1	[5]	[6]=[2]x(1+[5])	[7]=[6]-[3]	[8]=[7]/[6]
CAISO	No Escalation	0%	[a]	$1,180	$833	29%	41%	$1,667	$834	50%
CAISO	5 Years of Inflation	13%	[b]	$1,180	$942	20%	41%	$1,667	$725	43%
CAISO	Historical Escalation	41%	[c]	$1,180	$1,177	0%	41%	$1,667	$490	29%
MISO	No Escalation	0%	[d]	$181	$154	15%	18%	$215	$61	28%
MISO	5 Years of Inflation	13%	[e]	$181	$174	4%	18%	$215	$41	19%
MISO	Historical Escalation	18%	[f]	$181	$182	0%	18%	$215	$33	15%

Notes:

[2]: Values for CAISO and MISO are ISO estimates. Values reflect 10 projects in CAISO and two projects in MISO.

[3]=(1+[1])x[2]: Values are either the final cost estimate, latest cost estimate, or selected proposal cost estimate, depending on availability and relevance, taking precedence in that order.

Sources:

[2][a]: Please see Table 9.

[2][d]: Please see Table 7.

[5]: Please see Tables 17, and 18.

Table 24: Estimated Savings Across All

Region		Estimated Cost Savings	No. of Projects	Estimated Cost of Selected Proposals	Notes
		[1]	[2]	[3]	[4]
CAISO	**[a]**	29-50%	9	$833 million	Selected proposal costs compared to CAISO initial cost estimate; assuming a range of cost escalation for the selected bid of between zero to the level of historical average cost escalation of transmission projects in CAISO (+41%)
MISO	**[b]**	15-28%	2	$154 million	Selected proposal costs compared to MISO's initial cost estimate; assuming a range of cost escalation for the selected bid of between zero to the historical average cost escalation of transmission projects in MISO (+18%)
PJM	**[c]**	60-67%	1	$280 million	Selected proposal cost (including necessary incumbent upgrades) compared to the lowest-cost solution offered by incumbent in the initial proposal window; assuming a range of cost escalation of between zero to the historical average cost escalation of transmission projects in PJM (+22%)
NYISO	**[d]**	22%	1	$181 million	Selected proposal cost compared to lowest-cost bid from incumbent
IESO	**[e]**	16%	1	CAD 777 million	Selected proposal cost compared to bid from incumbent
AESO	**[f]**	21%	1	CAD 1,614 million	Selected proposal cost compared to AESO initial cost estimate; costs of the selected bid later increased due to changes in route
UK	**[g]**	23-34%	15	~£3,000 million	Selected bid cost estimate compared to merchant and regulated counterfactuals estimated by Ofgem
Brazil	**[h]**	~25% (20-40%)	Many	$28 billion	Based on Brazil's experience since 1999 holding auctions for all projects over 230 kV; over 50,000 km of lines built through this process

Sources:

SPP has been excluded due to cancelled project.

[a]: See Table 9: CAISO Competitive Projects Summary.

[b]: See Table 7: MISO Competitive Project Summary.

[c]: See Table 10: Selected PJM Competitive Projects Summary.

[d]: See Table 11: NYISO Competitive Project Summary.

[e]: See Table 14: Ontario Competitive Project Summary.

[f]: See Table 13: AESO Competitive Project Summary.

[g]: See Table 22: Summary of Experience with Competition in UK.

[h]: See ANEEL Transmission Auction Results.

BUILDING NEW TRANSMISSION

EXPERIENCE TO-DATE DOES NOT SUPPORT EXPANDING SOLICITATIONS

PREPARED BY:

Emma Nicholson, Meredith Stone, and Danielle Powers

PREPARED FOR:

Ameren, Eversource Energy, ITC Holdings Corp., National Grid USA, and PSE&G

June 2019

Table of Contents

EXECUTIVE SUMMARY

The value of electric transmission is significant and well documented. Transmission infrastructure provides customers with a reliable and resilient flow of power, integrates diverse and cost-effective energy resources, enables production cost savings, reduces amounts and costs of planning reserve margins, and increases competition among supply resources for the benefit of customers.[1] Incumbent transmission owners ("TOs") have made the majority of the transmission investments in the U.S. and, more recently, a number of transmission projects have been subject to competitive solicitation processes ("solicitations") and awarded to non-incumbent transmission developers. Some argue that these solicitations should be expanded. Proponents of such an expansion, including the Brattle Group in an April 2019 Report ("Brattle Report" or "report"), assert that expanding the scope of such solicitations will yield significant cost savings.[2]

The savings that will result from significantly expanding solicitations for new transmission projects, as claimed in the Brattle Report, are based in part on the assumption that transmission projects developed by incumbent TOs, as opposed to those selected through a solicitation, will experience significant cost escalations with final project costs exceeding initial estimates by 18-70%.[3] This assumption is false and inconsistent with the empirical evidence. Concentric found that incumbent TOs in independent system operators ("ISOs") and regional transmission organizations ("RTOs") that track project costs develop reasonable initial cost estimates, with final and/or updated project cost estimates falling between -2.9% and 7.0% of initial estimates.

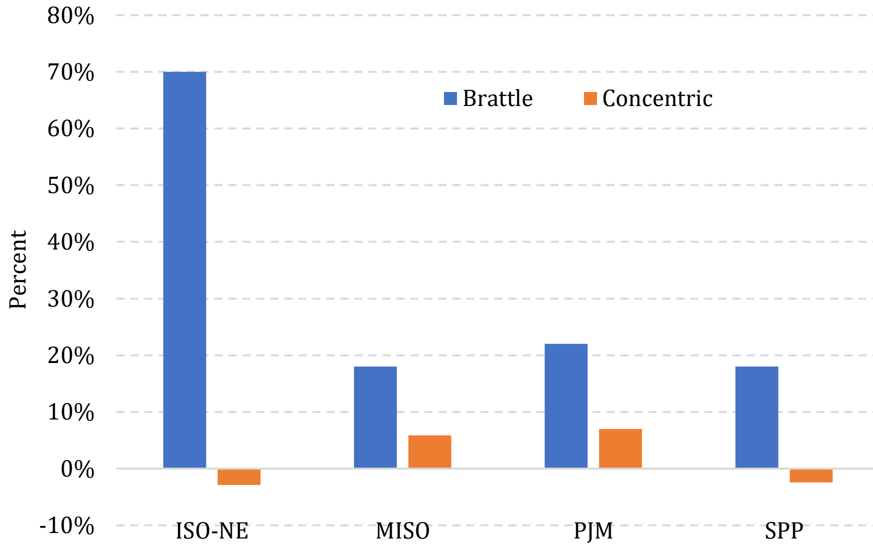
The methodological approach underlying the Brattle Report's recommendation that policymakers should expand solicitations also is fundamentally flawed. As such, there is no credible support for the claim that current transmission processes limit customer savings, or that expansion of competition will yield meaningful additional savings. The Brattle Report inappropriately compares different types of project cost estimates, fails to account for differences in scope between project cost estimates, and uses a limited and unrepresentative sample size of incumbent TO projects to produce its average historical cost escalation estimates, which are significantly overstated. Figure E1 below compares Concentric's estimates to the Brattle Report.

1 See e.g., Edison Electric Institute, Smarter Energy Infrastructure: The Critical Role and Value of Electric Transmission (March 2019).

2 The Brattle Group, *Cost Savings Offered by Competition in Electric Transmission*, (April 2019). ("Brattle Report" or "report").

3 Brattle Report p. 41, Figure 18, column 5.

Figure E1: Comparison of Concentric and Brattle Historical Cost Escalation Estimates for ISOs/RTOs with Cost Tracking Databases



Importantly, of the 15 projects that the Brattle Report used to calculate its cost savings estimates, the final cost of the majority of the projects is currently unknown. Although many of the winning bids have cost caps, many of the cost caps have exclusions and exceptions that permit the project's final cost to exceed the cost submitted in the initial winning bid. Furthermore, the cost cap exclusions for some projects apply to the project cost components with the highest risk of cost increases (e.g., routing changes). Final project costs that exceed the costs in the winning bid could erode a significant amount of the savings claimed in the Brattle Report.

While the Brattle Report acknowledges some of these flaws,[4] it nonetheless applies its estimate of cost savings to a much broader (and undefined) set of transmission projects and erroneously concludes that significant savings could be achieved by expanding solicitations to cover a larger portion of U.S. transmission investment, including investments made in regions that do not currently conduct solicitations for transmission projects.[5]

Concentric also reviewed the implementation details of the 15 solicitations upon which the Brattle Report's savings estimates are based and found that the solicitations were time and resource intensive. One of the most significant expenditures was time. For each solicitation, Table E-1 shows the time between the date the project need was first identified and final ISO/RTO Board approval of the winning bidder. The time involved to conduct solicitations with more than one bidder ranged from 113 days to 1,498 days.

---

[4] Brattle Report, p. 39.
[5] Brattle Report, p. 13.

Table E-1: Time involved in transmission solicitations

Project	Days Between Identification and ISO/RTO Board Approval
Imperial Valley	113
Gates-Gregg	231
Sycamore Penasquitos	349
Suncrest	174
Delany Colorado River	359
Estrella	238
Harry Allen to Eldorado	544
Miguel†	55
Spring	238
Wheeler Ridge	238
Duff Coleman	385
Hartburg-Sabine	361
Walkemeyer	448
Artificial Island	1,498
AP South	893
NY Western Public Policy	820
AC Transmission	1,208

† The Miguel solicitation had a single bidder – San Diego Gas & Electric. See Table 12 for more details about the timeline of each solicitation.

Time is an important consideration because delayed project development denies customers the benefits of transmission investments, such as reduced congestion costs or increased reliability. Significantly expanding solicitations would also conflict with Federal Energy Regulatory Commission ("FERC" or "Commission") precedent established in the Order No. 1000 proceeding. Furthermore, the time, money and resources these solicitations would require should not be overlooked because such costs could make conducting a solicitation for certain types of projects (e.g., upgrades) uneconomic. Concentric reviewed the claims in the Brattle Report as well as additional information about the solicitations held to date. Based on this review, we find the Brattle Report's claims that the solicitations held to date have produced significant savings to be baseless. Claims that expanding the solicitations would yield up to $9 billion in savings[6] are without merit and should not be relied upon to justify any expansion of solicitations for new transmission projects.

[6] Brattle Report, p. 13

1. Introduction

In 2011, the Federal Energy Regulatory Commission ("FERC" or "Commission") issued Order No. 1000. Among other things, Order No. 1000 requires jurisdictional public utility transmission providers to produce a regional plan to meet the region's transmission needs more efficiently or cost-effectively.[7] The six FERC-jurisdictional independent system operators ("ISOs") and regional transmission organizations ("RTOs") that are required to comply with FERC Order No. 1000 chose to select certain new types of transmission projects through solicitation processes.[8]

More recently, proponents of expanded solicitations for transmission, including the Brattle Group in a recent report ("Brattle Report" or "report") have advocated that transmission solicitations should be significantly expanded because doing so will purportedly reduce customer costs by up to 30%.[9]

Based on Concentric's review, the savings claimed in the Brattle Report are inaccurate and do not provide a basis to expand the scope of solicitations in FERC-jurisdictional ISOs/RTOs or anywhere else. First, it is not possible to estimate potential savings from the solicitations held to-date because the final costs of most projects are not known and the cost caps in some of the winning bids are not guaranteed to contain final costs. Second, the savings claimed in the Brattle Report are without merit. The report's lower bound savings estimates for the solicitations are flawed because Brattle uses an inappropriate benchmark to estimate savings from those solicitations. The upper bound savings estimates are also methodologically flawed and rely on over-stated "cost overrun" estimates for incumbent Transmission Owners ("incumbent TOs"). Concentric's review of publicly available ISO/RTO cost tracking data suggests that incumbent TOs experience fairly modest cost changes, which are negative in some ISOs/RTOs, with final or updated project cost estimates varying from initial cost estimates by between -2.9% to 7.0%, in the ISOs/RTOs with publicly available cost tracking databases.[10] Given the risks inherent with transmission development, in our view incumbent TOs have demonstrated an ability to develop reasonably accurate cost estimates that appropriately account for project risks.

The remainder of this report is organized as follows: Section 2 discusses the Brattle Report's claims that the transmission projects developed by incumbent TOs experience significant cost escalations and presents Concentric's analysis of the same data that yields different results. Section 3 examines Brattle's claims that the solicitations held to-date produced significant cost savings. Section 4 explains that transmission solicitations

---

7 Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, 136 FERC ¶ 61,051 (July 21, 2011) ("Order No. 1000").

8 Non-ISO/RTO regions that are FERC-jurisdictional are also required to comply with Order No. 1000 reforms, however, these non-ISO/RTO regions do not conduct solicitations for new transmission projects as part of their regional transmission planning process and are thus not discussed in this report.

9 Brattle Report, p. 13, Figure 4.

10 The ISO/RTOs with cost tracking database are: ISO New England, Inc. ("ISO-NE"); Midcontinent Independent System Operator ("MISO"); Southwest Power Pool ("SPP"); and PJM Interconnection ("PJM").

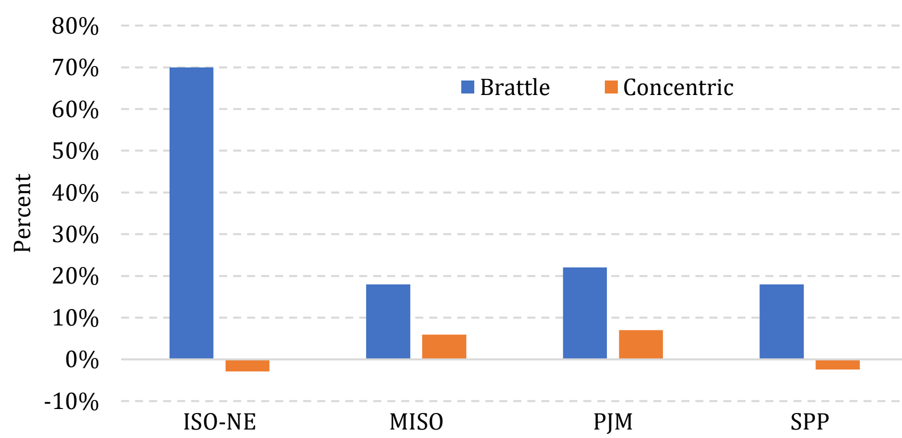
are time and resource intensive, a consideration that must be weighed before expanding the scope of such solicitations. Section 5 explains that Brattle's recommendation to expand the scope of solicitations would be inconsistent with the Commission's reliability and resilience goals and would require the Commission to revisit prior findings in Order No. 1000 and in other orders. Section 6 summarizes the report's findings and concludes that, based on Concentric's review of the evidence to-date and the claims made in the Brattle Report, there is no basis to expand the scope of transmission projects that are selected through solicitations at this time.

2. INCUMBENT TRANSMISSION OWNER INITIAL COST ESTIMATES ARE ACCURATE

The Brattle Report claims that transmission investments that are not selected through a solicitation, but instead developed by incumbent TOs in ISOs/RTOs, experience cost escalations ranging from a low of 18% in SPP and MISO to a high of 70% in ISO-NE.[11]

Concentric first performed its own analysis using the same data relied upon in the Brattle Report to assess the accuracy and reasonableness of the claims about incumbent TOs. Where possible, Concentric also analyzed publicly available ISO/RTO transmission project tracking databases that provide more comprehensive information of initial and final and/or updated project cost estimates to produce our own estimates. Figure 1 and Table 1 compare the Brattle Report and Concentric estimates of the extent to which incumbent TO initial transmission project cost estimates exceed final costs and/or updated cost estimates. As described further below, Concentric's analysis shows that the difference between the initial and final and/or updated cost estimates of incumbent TO projects is fairly modest or negative, ranging from -2.9% to 7.0% for four of the five ISOs/RTOs reviewed, and less than half of what the Brattle Report estimates for the fifth ISO, California ISO ("CAISO").

Figure 1: Comparison of Concentric and Brattle Historical Cost Escalation Estimates for ISOs/RTOs with Cost Tracking Databases



11 Brattle Report, Figures 21, 22, 24 and 25.

Table 1: Comparison of Concentric and Brattle Incumbent TO Historical Cost Escalation Estimates

ISO/RTO	Brattle	Concentric
CAISO*	41%	PG&E: 6.1 to18.8% SDG&E: 5.9%
ISO-NE	70%	-2.9%
MISO	18%	5.9 %
NYISO	n/a	n/a
PJM	22%	7.0%
SPP	18%	-2.4%

Source: Brattle estimates are from Brattle Report, p. 41, Figure 18, column 5. Concentric estimates are discussed herein. CAISO does not have a cost tracking database so Concentric's estimates for PG&E and SDG&E projects are not representative of either CAISO as a whole or of these TOs' full portfolio of projects. The CAISO estimate is only provided for purposes of comparison with the Brattle Report's CAISO estimate.

The methods used in the Brattle Report to estimate the "average historical cost escalations" of incumbent TO projects are flawed and produce inaccurate and misleading results. The Brattle Report's "average historical cost escalation" estimates are based on a limited sample of projects that are not representative of the full portfolio of incumbent TO projects in each ISO/RTO. As discussed further below, for ISO-NE, SPP, and CAISO, the Brattle Report compared early high-level estimates that were made before the scope of the project was finalized, which is a meaningless comparison that is not informative about the accuracy of incumbent TO initial cost estimates. The Brattle Report also ignored a significant number of transmission projects in ISO-NE, PJM, and SPP. Thus, the Brattle Report's estimated cost escalation results are based on a small sample that did not reflect the full portfolio of incumbent TO projects in these ISOs/RTOs or the ability of incumbent TOs to produce accurate initial cost estimates for their respective projects. Furthermore, many of the planning processes were intentionally designed to foster stakeholder involvement and collaboration, with early-stage, conceptual cost estimates refined over time based on stakeholder discussion and, eventually, proceedings before state regulatory authorities. In our view, the estimates of historical cost escalation in the Brattle Report should not be used to draw inferences about the accuracy of incumbent TO initial cost estimates. As discussed further below, it is more appropriate to examine the full portfolio of incumbent TO transmission projects in order to draw conclusions about the accuracy of initial cost estimates.

Using a broader sample, Concentric finds that the difference between initial cost estimates and final or updated project cost estimates are quite modest (see Table 1), and in some cases, final or updated costs are below initial cost estimates. As discussed further in Section 3, the Brattle Report used these flawed and overstated "historical cost escalations" to estimate that solicitations for new transmission projects will save 22% to 67% compared to designating the incumbent TO as the project developer.[12]

12 Brattle Report, p. 43, Figure 19.

Before discussing our analysis of incumbent TO cost estimates, it is important to provide context for the nature of transmission development. Building transmission infrastructure, particularly large greenfield projects, involves a dynamic set of technical, economic, and regulatory assumptions that affect schedule and cost. Transmission developers review and report cost estimates throughout the project development cycle.

While the nomenclature of these estimates differs by ISO/RTO, the estimates broadly fall into the three stages: conceptual, planning, and engineering/construction. The development of a transmission project's initial cost estimate takes place early in the planning process. For example, high-level conceptual and planning estimates are often used to compare alternative solutions and are more conceptual in nature. Because these estimates are based on conceptual plans or proposals rather than specific projects, they do not reflect detailed design or engineering considerations. As the project proceeds through its development cycle, updated estimates based on the latest information are developed and released.

The precision of these cost estimates differs by stage and increases as the project progresses from the conceptual stage to the design, engineering, and construction stages.[13] For example, equipment cost estimates become more accurate once the developer learns more about the specifics of the equipment needed and obtains supplier quotes; and this information would be included in an estimate produced during the engineering and/or construction stage of development. For greenfield projects, the precision of the cost estimate increases as information about the transmission line's route and design is refined during the permitting process, which enables the developer to produce more accurate estimates of construction and permitting costs. Such uncertainties are typically beyond the developer's control – regardless of whether or not the developer is an incumbent. Given these uncertainties, transmission project developers frequently include contingencies in their initial cost estimates. Accordingly, great care must be taken in comparing different types of project cost estimates because comparing two different cost estimates without understanding the nature of each estimate could result in a meaningless or uninformed comparison. As discussed further below, we believe many of the conclusions and estimates in the Brattle Report are based on such inappropriate comparisons.

The remainder of this Section identifies the flaws in the Brattle Report's comparisons of incumbent TO initial and final or updated project cost estimates in each ISO/RTO where such an analysis was possible. We then present our own analysis, which uses a broader sample of incumbent TO projects and, where appropriate, accounts for differences in the nature of the initial cost estimates, to assess the accuracy of incumbent TO initial project cost estimates. In our view, Concentric's estimates are more accurate than the Brattle Report estimates because they are based on a more complete portfolio of projects, and thus are more representative of average incumbent TO cost performance.

13 See Appendix B for more details.

The differences between incumbent TO initial and final and/or updated project cost estimates are noteworthy considering the iterative nature of estimating transmission project costs, which become more accurate over time as better information about the project becomes available. In an effort to be conservative and to be consistent with the Brattle approach, Concentric's estimates of how incumbent TOs' initial and final project costs compare do not adjust for inflation. Inflation accounts for some of the difference between initial and final cost estimates, so accounting for inflation would have reduced our estimates of historical cost escalations. Below we present our analysis of the accuracy of initial project cost estimates in ISO-NE, MISO, SPP, PJM, and CAISO.

2.1. ISO-NE

The Brattle Report claims that, on average, the actual costs for ISO-NE incumbent TO projects exceeded initial estimated costs by approximately 70%. The report only relied on 14 transmission projects that were developed by ISO-NE incumbent TOs, some proposed as early as 2002, to estimate the average historical cost escalation for all ISO-NE transmission projects. These 14 projects represent less than 2% of all projects placed in-service across New England since 2002. For 3 of the 14 projects, the Brattle Report relied on a publicly available cost tracking database and Concentric was able to validate the costs of these projects.[14] For the remaining 11 projects, the Brattle Report relied on a 2015 presentation.[15] Concentric examined these 11 projects and also conducted an analysis on the full portfolio of incumbent TO projects in ISO-NE using the ISO-NE project cost tracking database. Based on this broader and more representative sample of ISO-NE incumbent TO projects, Concentric found that final project costs in ISO-NE were actually 2.9% *below* initial estimates.

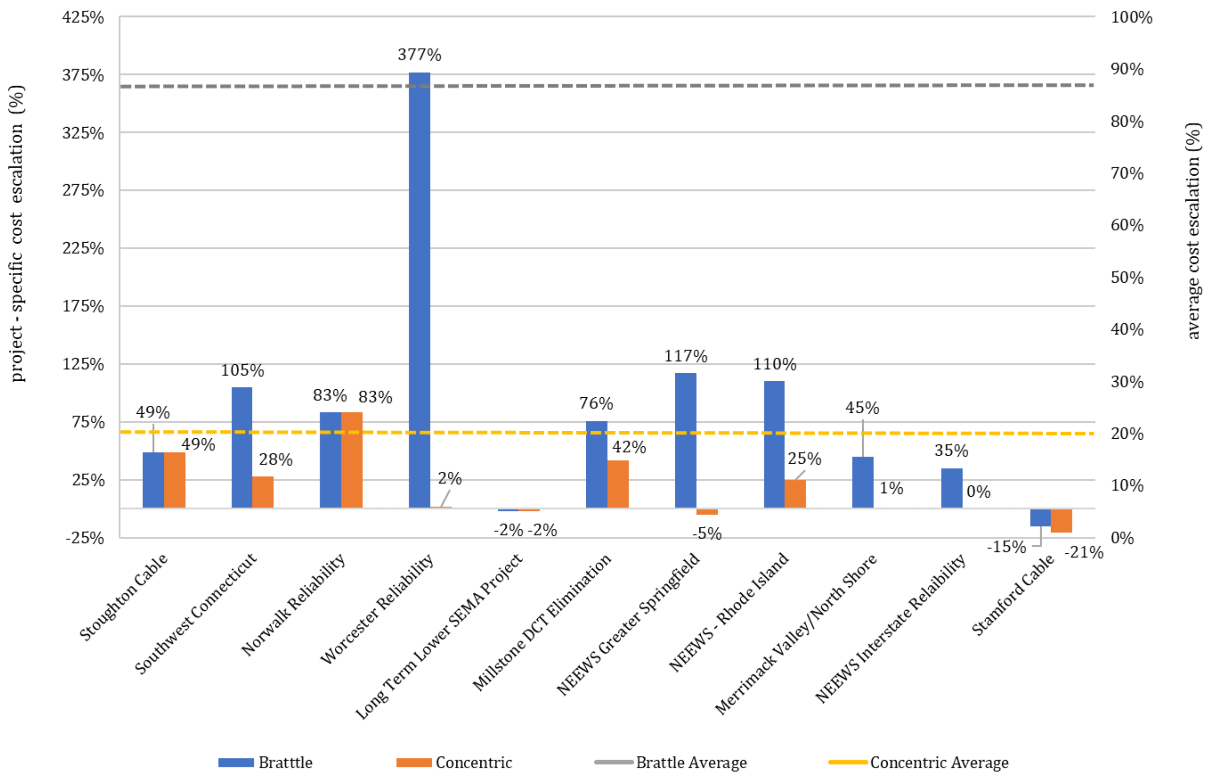
As a first step in assessing incumbent TO project costs in ISO-NE, Concentric reviewed the construction costs of 11 of the 14 transmission projects the Brattle Report based its 70% cost escalation estimate on. The Brattle Report used the initial cost estimate published by ISO-NE at the time the project was first proposed but *before* a scope was fully defined or detailed engineering performed for the project. As noted above, estimates that are developed early in the planning process are, by definition, high-level estimates that are based on a loosely defined scope. Concentric's analysis of the 11 projects used the same final project costs as the Brattle Report but a different and more appropriate initial cost estimate. For initial cost estimates, we used the estimated cost contained in the siting application of each project rather than the first estimates published (which were developed before key project decisions – such as overhead versus underground construction – were made). The cost estimate in the siting application reflects the project's actual scope, which is much better understood at the beginning of the siting/permitting phase. At this point in time, the incumbent TO developers have enough detail to more accurately estimate the cost of the proposed projects. Figure 2shows that if the project cost

14 Specifically, the Scobie-Tewksbury, Wakefield-Woburn, and Mystic Woburn projects, which the Brattle Report obtained initial and updated cost estimate data from the March 2018 RSP tracking database. *See* Brattle Report, p. 57, Figure 25.

15 NextEra Energy Transmission, Greater Boston Cost Comparison, January 2015.

estimate contained in the project siting application is used, final project costs for the 11 projects examined exceeded estimated costs by 18%, which is far less than the 70% estimate in the report. See Appendix A for more details about the analysis described in Figure 2.

Figure 2: Recalculation of Brattle's Cost Escalations with Corrected Cost Estimates



In our view, Concentric's comparison is much more meaningful and produces a more accurate cost variance estimate because the cost estimate in the siting application is much closer in scope to the final project, and more in-line with an estimate that would be provided as part of a solicitation. Thus, Concentric's analysis uses two estimates that are reasonably comparable, whereas the Brattle Report compares two figures that are not comparable in any useful or informative way. It warrants mention that ISO-NE processes have evolved since the 11 projects, some of which were initially proposed in 2002. ISO-NE incumbent TOs now use multiple cost estimates throughout the planning process that reflect varying degrees of scope definition at the time the estimates are developed.

In addition to inaccurately representing project "cost escalation", the sample of projects the Brattle Report used to estimate historical cost escalations does not constitute a representative sample of incumbent TO projects in ISO-NE. The 11 projects, many of which were complex greenfield projects, have a much higher escalation risk – regardless of who develops the project.

In an effort to develop a more representative estimate of cost escalation for incumbent TOs in ISO-NE, Concentric used a publicly available ISO-NE transmission cost tracking database that tracks most significant transmission projects in ISO-NE. ISO-NE's regional transmission planning document is called the Regional System Plan ("RSP"). The "RSP Project List" tracks cost information about reliability projects in the RSP (generally those with estimated costs above $5 million) and tracks how cost estimates for projects change over time.

Concentric used data on reliability upgrade projects from the March 2019 RSP Project list. We used the estimate from the time the incumbent TO received approval of its Proposed Plan Application ("PPA") as an initial cost estimate. At this point in time, the necessary components of a project are generally defined with a sufficient level of detail to yield a reasonably accurate cost estimate. For an updated cost estimate/final cost, as applicable, Concentric used the cost estimate available in the March 2019 RSP Project List. As shown in Table 2, comparing the initial and current (as of March 2019) cost estimate shows that, in aggregate, incumbent TOs in ISO-NE had final/updated cost estimates that were 2.9% below the initial cost estimates in the PPAs.

Table 2: ISO-NE Incumbent TO Initial and Final or Updated Project Cost Estimates

In-Service Year	Aggregated project cost estimates from Proposed Plan Application ($ million)	Updated cost estimates or final costs as of March 2019 ($ million)	Difference (%)
2011	$265.2	$248.2	-6.4%
2012	$410.2	$411.1	0.2%
2013	$1,230.2	$1,165.3	-5.3%
2014	$457.5	$440.6	-3.7%
2015	$751.4	$716.3	-4.7%
2016	$364.2	$377.1	3.6%
2017	$260.9	$271.0	3.9%
2018	$157.0	$153.8	-2.0%
Total	$3,896.7	$3,783.5	-2.9%

Notes: Table compares all reliability upgrade projects in service between 2010 and 2018 based on projects tracked in ISO-NE's March 2019 RSP Project List tracking database. Figures reported in nominal dollars for all projects with cost information on both the Proposed Application Plan estimate and an updated estimate or final project cost. The RSP Project list generally contains only projects with costs above $5 million.

Concentric's estimate is based on a sample of 150 projects - a much broader sample than the 11 projects reviewed in the Brattle Report - to estimate how ISO-NE incumbent TO initial cost estimates compare to updated or final project costs. The estimates in Table 2 are presented in nominal dollars (accounting for inflation would make the cost decrease even bigger), and are significantly below the 70% "cost escalation" estimate in the Brattle Report.

2.2. MISO

Brattle estimates that the costs of MISO's incumbent TO projects have increased by 18% for the 2015-2018 planning cycles. Because Concentric could not replicate the figures shown in Brattle's Figure 21, we are unable to review Brattle's methodology. However, Concentric reviewed the same publicly available transmission project cost data relied upon by Brattle, which shows that cost escalations ranged from 0.5% to 7%, far lower than the Brattle results.

Table 3: MISO Facility Cost Change Estimates

	Initial ($million)	In-Service ($million)	% Change
MTEP 2014	$ 9,085	$ 9,747	7.3%
MTEP 2015	7,292	7,615	4.4%
MTEP 2016	6,304	6,675	5.9%
MTEP 2017	478	480	0.5%
Total	**$ 23,159**	**$ 24,517**	**5.9%**

Concentric reviewed the change between initial estimates and in-service costs for projects approved in the 2014-2017 MISO Transmission Expansion Plans ("MTEP"). This analysis is discussed further in Appendix A. In total, these projects have experienced a 6% cost escalation.

2.3. SPP

Brattle estimates that the costs of SPP's incumbent TO projects developed from 2009 through 2019 experienced cost escalations of 18%. Concentric determined that this estimate is significantly overstated. Table 4 shows the Brattle Report's cost escalation estimates for Balanced Portfolio Projects, Priority Projects, and ITP Portfolio Projects in SPP. In total, Brattle claims that costs have increased from $2,028 million to $2,391 million (without controlling for inflation), for a total cost escalation of 18%. However, upon closer review of each category of projects using the same data sources, Concentric determined that these projects actually experienced a "cost escalation" of negative 2%.

Table 4: SPP Incumbent TO Project Cost Estimates

SPP Portfolio	Brattle Initial TO Cost Estimate ($ million)	CEA Initial TO Cost Estimate ($ million)	Latest Cost Estimate ($ million)	Brattle Estimated Cost Escalation	CEA Estimated Cost Escalation	# of Projects
Balanced Portfolio	$691	$832	$831	20%	0%	
Priority Projects	$1,145	$1,416	$1,349	18%	-5%	
ITP Portfolio Projects with Final Cost Estimates (2012 to 2017)	$192	n/a	$211	10%		42
ITP Portfolio Projects Listed as Complete (2012 to 2017)	n/a	$1,349	$1,330	n/a	-1%	150
Brattle Total Comparison	$2,028	$2,249	$2,391	18%	n/a	
Concentric Total Comparison	n/a	$3,597	$3,510	n/a	-2%	

As discussed further in Appendix A, the initial estimates used in the Brattle Report for the Balanced Portfolio and Priority Projects were based on initial project scopes that were revised at the direction of SPP. As such, most of the escalation the Brattle Report estimates for these projects is due to a change in scope rather than action or lack of cost discipline on the part of the incumbent TO developers. Thus, the Brattle Report estimates of historical cost escalations in SPP and ISO-NE are flawed for similar reasons – they inappropriately compare different types of project cost estimates and in both cases, compare projects of different scopes.

2.4. PJM

The Brattle Report estimates that the costs of PJM's incumbent TO projects experienced escalations of 22% relative to initial cost estimates.[16] To produce this estimate, Brattle appears to use data selectively that significantly underrepresents the PJM projects with cost tracking data. To produce an estimate for PJM, Concentric expanded the sample of transmission projects by including all projects that had both initial and updated cost information in the PJM cost tracking database and concluded that the updated cost estimates of PJM TOs only exceeded initial estimates by 7.0%.

Concentric first attempted to recreate the PJM estimate in Figure 24 of the Brattle Report, which analyzed Baseline Reliability and Network Upgrade projects in service or under construction during the 2014-2017 period. Concentric analyzed the data sources cited in the Brattle Report to support this estimate but was unable to reproduce the estimate. However, based on our review which is summarized in Table 5, it is clear that the Brattle Report estimate only included a subset of the Network Upgrade and Baseline Reliability projects. As shown in Table 5, the Brattle Report estimate included $4,520 million in projects while the Concentric estimate, which is based on all Network Upgrade and Baseline Reliability projects for which initial and updated cost

16 Brattle Report, Figure 24, p. 56.

information is available, includes $12,999 million in projects. For unknown reasons, the Brattle Report's estimate for PJM cost escalation excluded about two-thirds of the incumbent TO Baseline Reliability and Network Upgrade projects, despite the fact that information was available for those projects.[17] Concentric's analysis of the full sample of Baseline Reliability and Network Upgrade projects (shown in Table 5) found that updated cost estimates for Baseline Reliability and Network Upgrades were 5.2% above initial estimates on average, which is a quarter of Brattle's 22% "cost escalation" estimate.

Table 5: PJM Initial and Latest Project Costs Estimates for Baseline Reliability and Network Upgrade Projects

	Initial Estimate ($ million)	Latest Estimate ($ million)	Latest vs. Initial Estimate (%)
Brattle Report Estimates			
2014	822	971	18%
2015	1,722	2,124	23%
2016	768	940	22%
2017	382	485	27%
2014-17 total	3,694	4,520	22%
Concentric Estimates			
2014	2,818	3,075	9.1%
2015	4,331	4,545	4.9%
2016	3,471	3,581	3.2%
2017	1,732	1,798	3.8%
2014-17 total	12,352	12,999	5.2%

Notes: Source of Brattle Report Estimates: Brattle Report, p. 56, Figure 24. For Baseline Reliability Projects, initial cost estimates are from the PJM Transmission Cost Allocation Database (May 1, 2019 version) and latest cost estimates are from the Construction Status Database. For Network Upgrades, the initial cost estimates are from the 2014-2017 TEAC Whitepapers and the latest cost estimates are from the Construction Status Database. Project years are based on the Display Service Date from the Transmission Cost Allocation Database. The above figures only reflect projects for which both initial and latest cost estimate data are available and are not adjusted for inflation.

The Brattle Report estimates for PJM excluded Supplemental Projects, which constitutes the third category of transmission projects in PJM. In an effort to use a larger and more representative sample of incumbent TO projects in PJM, Concentric performed an analysis that also includes Supplemental Projects, which increases the sample of projects (as measured by latest project cost estimates) by 44%.

17 According to the notes of Table 15 of the Brattle Report, Brattle excluded the 72% of projects where the initial and latest cost estimates were the same, stating that "it is unclear whether these reported latest estimated costs in PJM's database are appropriately reflective of actual cost changes in Projects' cost estimates, therefore they have been excluded" from the Brattle Report estimate. However, we found no documentation or basis to exclude these data.

Table 6: PJM Initial and Latest Project Costs Estimates for Baseline, Network Upgrade, and Supplemental Projects

	Initial Estimate ($ million)	Latest Estimate ($ million)	Latest vs. Initial Estimate (%)
2014	3,621	4,023	11.1%
2015	5,361	5,746	7.2%
2016	4,685	4,899	4.6%
2017	3,858	4,087	5.9%
2014-17 total	**17,525**	**18,755**	**7.0%**

Notes: see notes for Table 5 for the source of the Baseline and Network Upgrade project cost figures. Supplemental Project initial and updated project costs are from the PJM Transmission Cost Allocation Database (May 1, 2019 version).

Based on this expanded sample size, shown in Table 6, updated project cost estimates for PJM incumbent TOs exceeded initial cost estimates by 7.0%, significantly below the 22% estimate in the Brattle Report.

2.5. CAISO

Unlike ISO-NE, MISO, PJM, and SPP, CAISO does not publish a centralized and publicly available transmission project cost tracking database. (Neither does the New York ISO ("NYISO").) As such, it is not possible to conduct a robust and accurate analysis of the initial and final and/or updated project costs for the full portfolio of transmission projects in CAISO or NYISO. Nevertheless, Concentric conducted an analysis to assess the reasonableness and accuracy of the Brattle Report estimates for CAISO.

The Brattle Report claims, based on an analysis of 10 projects,[18] that incumbent TOs in CAISO have experienced a 41% cost escalation on average.[19] Concentric reviewed the methodology Brattle used to estimate cost escalation in CAISO and determined that, much like the report's estimates for ISO-NE, the CAISO cost escalation estimate is inaccurate because it is based on a small and unrepresentative sample of projects. Concentric's analysis, described further in Appendix A, demonstrates that the limited sample that Brattle used to calculate its estimate should not be used to draw inferences about incumbent TO cost escalations in CAISO as a whole.

Given the lack of data, Concentric cannot confidently perform an analysis of the accuracy of CAISO incumbent TO initial estimates by comparing them to final project costs. However, Concentric found that analyzing a larger sample of projects based on information that was available in the FERC dockets cited in the report, casts doubt on the Brattle Report's estimates and suggests that CAISO incumbent TOs do not experience an average cost escalation of 41% as the report claims. Table 7 demonstrates the implication of expanding the sample to include all of the projects for which initial and final project cost information is available. Expanding this sample

18 The Brattle Report analyzed 7 PG&E projects and 3 SDG&E projects. See e.g., Brattle Report, Figure 23.

19 Brattle Report, Figure 23, p. 55.

reduces the average cost escalation for PG&E from 52.7% to between 6.1% and 18.8% and increases the cost escalation estimate for SGD&E from 2.3% to 5.9%.

Table 7: Concentric Review of Brattle Report Historical Cost Escalation Estimate for CAISO

	Number of Projects	Initial Estimate ($)	Final Cost ($)	Final Cost – Initial (%)
Pacific Gas & Electric				
Full available sample	55	$1,534.7-$1,718.1	$1,823.5	6.1-18.8%
Brattle Sample	7	$668.6	$1,021.1	52.7%
San Diego Gas & Electric				
Full available sample	17	$782.4	$828.9	5.9%
Brattle Report sample	3	$199.1	$203.7	2.3%

Note: PG&E initial estimates were provided as a range to CPUC in Docket No. EL17-45-000 so the initial cost estimates are also provided as a range for these projects. For projects in Docket No. EL16-2330, the initial estimates were those PG&E submitted to CAISO, and not the high range of the "CAISO estimate" referenced in Figure 23 of the Brattle Report.
SDG&E projects: *California Parties v. Pacific Gas and Electric Co.*, Docket No. EL17-45-000, Exhibit No 3 - SDG&E Response to CPUC Data Request, p. 7 (filed Feb. 2, 2017). Information provided for projects completed between January 2014 and November 2016.

The 41% escalation estimate for CAISO in the Brattle Report does not include any Southern California Edison projects despite the fact that it is the second largest incumbent TO in CAISO. Taken as a whole, Concentric found that the Brattle Report estimate for CAISO was not representative of the full portfolio of incumbent TO projects and inexplicably excluded certain transmission projects.

In conclusion, Concentric found the Brattle Report claims of 18% to 70% cost escalations in the ISOs/RTOs we reviewed to be inaccurate. After conducting a thorough review of publicly available information, we found a fairly modest margin, which is negative in some ISOs/RTOs, between incumbent TO initial project estimates and final project costs. As such, the Brattle Report estimates of incumbent TO cost escalations should not be used to draw inferences about initial and final transmission project costs in ISO-NE, MISO, SPP, PJM, or CAISO.

A simplistic and narrow focus on whether solicitations result in cost savings ignores the broader and important considerations of benefits associated with historical models of incumbent ownership and management of transmission systems. These benefits represent possible opportunity costs of competitive solicitations, which must be considered in addition to the direct costs, benefits, and uncertainties of the solicitations held to date.

3. Benefits of Transmission Solicitations are Unknown

Concentric reviewed the methodology used in the Brattle Report to estimate the savings from 15 solicitations (see Table 8).[20] As an initial matter, it is not yet possible to determine the cost impacts of these solicitations because only one[21] of the projects selected through the solicitations is in service. Of the remaining 14, two have been canceled,[22] and the rest are in various degrees of development, as the Brattle Report notes.[23] In addition, the methods used in the Brattle Report to estimate savings from the 15 solicitations were flawed. As such, the final costs of the majority of the projects selected in these solicitations are unknown and unknowable at this time, and any resulting savings are also unknown.

MISO and NYISO have each held two solicitations, SPP has held one, and ISO-NE has not held any, although ISO-NE plans to hold a solicitation in the near future.[24] However, Massachusetts, a state within the ISO-NE footprint, issued a request for proposals ("RFP") for hydroelectric power or other clean energy and the transmission capacity to deliver it, and selected a developer in 2018.[25] Prior to this solicitation, Massachusetts, Connecticut, and Rhode Island jointly conducted the Clean Energy RFP that included options for new transmission. These solicitations took place outside of ISO-NE's regional transmission planning process.

Table 8: Transmission Solicitations Through ISO/RTO Regional Planning Processes as of April 2019

ISO/RTO	Number of Solicitations	Solicitations Included in Brattle Savings Estimates
CAISO	10	10
PJM	136	1
MISO	2	2
NYISO	2	1
SPP	1	1
ISO-NE	0	n/a

Source: Brattle Report, Figures 10-14 and Table 6. Notes: Although Brattle estimates savings for 10 CAISO solicitations, it only includes 9 of these in its Figure 19 because the Gates Gregg project was delayed. In addition, Brattle only estimates the savings from solicitations awarded to non-incumbents, and therefore ignores solicitations in PJM.

As noted above, the methods used in the Brattle Report to estimate savings from the 15 solicitations were flawed. First, Brattle used inappropriate benchmarks to estimate the lower bound of the potential savings.

[20] Brattle Report, p. 28, Figure 10. Note that although Figure 10 references the AP South project in PJM and the Western NY project in NYISO, it did not rely on these solicitations in its analysis because both solicitations were won by incumbents. Additionally, the AC Transmission project had two segments (A and B) but NYISO sought proposals through a single solicitation.

[21] SDG&E completed construction of the Sycamore-Peñasquitos project in August 2018. See e.g., https://www.cpuc.ca.gov/Environment/info/panoramaenv/Sycamore_Penasquitos/index.html

[22] The Walkemeyer project in SPP was canceled and CAISO delayed the Gates Gregg project indefinitely.

[23] Brattle Report, p. 39. For example, the report states "[w]hile many of the winning proposals include cost caps or cost control measures, the completed costs of these projects are not yet known and may exceed the selected projects' offer prices."

[24] ISO-NE anticipates conducting a solicitation for a transmission project to meet reliability needs in the Boston Area later this year. ISO-NE previously considered holding a solicitation for the Keene Road area but determined after performing a cost-benefit analysis that it was not beneficial to do so.

[25] *See e.g.*, New England Clean Energy Connect (https://www.necleanenergyconnect.org/project-overview). The state of Maine granted this project a CPCN in April 2019. *See* https://www.necleanenergyconnect.org/necec-milestones.

Second, the report used the overstated incumbent TO "average historical cost escalation" estimates discussed in Section 2 to estimate the upper bound of the potential savings. With these flaws, the Brattle Report's estimated savings from the solicitations should not be relied upon for decision-making purposes.

The remainder of this section discusses Concentric's review of the Brattle Report's claims about the cost savings from the solicitations. Section 3.1 discusses the fact that the final costs of the projects are not known for the majority of the projects and describes the exclusions to the cost caps contained in some of the winning bids. Section 3.2 describes Concentric's review of claims in the Brattle Report that solicitations saved between 18% and 67%. We identified significant issues with these savings estimates. Section 3.2.1 describes the inappropriate benchmarks Brattle used to calculate its lower bound of savings estimates and Section 3.2.2 explains why the upper bound savings estimates are methodologically flawed.

3.1. Final Project Costs are Unknown

Of the 15 projects that Brattle uses to calculate its cost savings estimates, the final costs of the majority of the projects is unknown, so it is impossible at this time to determine the actual cost escalations, if any, associated with the majority of the projects awarded through the solicitations. Nevertheless, Brattle claims without any evidence that "on average [competitively-developed] projects may not escalate as much as other regional transmission projects have historically" as a result of bidder due diligence and cost caps. This claim is speculative given the lack of final cost data and cost cap exclusions described below. Furthermore, as shown in Section 2, incumbent TOs experienced a fairly modest margin between their initial and final or updated project cost estimates on average, with final or updated project cost estimates falling below initial estimates, on average, in some ISOs/RTOs.

The Brattle Report argues, in part, that the solicitations will result in cost savings because the winning bids in some of the solicitations contained cost caps. However, any cost-savings associated with the projects selected through the solicitations held to date cannot be known until the projects are in service. In addition, as the Brattle Report notes, cost escalations are often unavoidable during the development process (e.g., uncertainties around materials and labor costs, or scope and routing changes due to regulatory siting and approval issues). Furthermore, some cost cap provisions have exclusions that permit the final cost of the winning proposal to exceed the cost of the developer's bid.[26]

These exclusions tend to cover the costs that are the most likely to increase by the greatest amount during the development process (e.g., route changes, regulatory issues). For example, the Duff-Coleman solicitation in MISO resulted in 11 competitive proposals, 10 of which included at least one type of cost cap.

26 Brattle Report, pp. 40-41.

Table 9: Duff-Coleman Solicitation Cost Caps

Summary of Cost Caps, Concessions, and Commitments											
Uncertainty	**101**	**102**	**103**	**104**	**105**	**106**	**107**	**108**	**109**	**110**	**111**
ROE		✓		✓[i]			✓	✓[ii]	✓[iii]	✓	
Capital Structure		✓		✓						✓	
Implementation Costs	✓[iv]	✓[v]	✓	✓[iv]		✓	✓	✓	✓[iv]	✓	✓[iv]
Operations and Maintenance Costs				✓							
Inflation Rate			✓	✓		✓		✓		✓	
Rate Concessions						✓					✓

i Limited duration ROE cap

ii Cap on weighted average cost of capital (includes ROE), limited duration

iii No ROE cap, but will forego ROE incentive adders in initial FERC filing

iv AFUDC is not included in the cap

v Only a portion of construction costs are capped

Source: Duff-Coleman Selection Report, Table 2-2, p. 26.

The Duff-Coleman bids also included various exceptions to cost caps, or other concessions, as shown in the table below.

Table 10: Duff Coleman Selection Report Cost Cap Exception Summary

Exclusion	**Details**
1. Project Routing	Some proposals exclude routing changes due to unseen soil conditions, river crossings, etc. Combination of general outs and specific per mile cost values (with/without dead band).
2. Material Escalation Costs	Some proposals include exceptions for construction costs that arise above inflation rate
3. Condemnation and Property Rights	Some proposals allow an increase to the construction cost cap for condemnation and property rights costs that exceed a specified percentage dollar value.
4. Five Year or Initial Filing Commitments	Some proposals commit to a cap for condemnation and property rights costs that exceed a specified percentage or dollar value
5. Regulatory	Some proposals note exclusions for environmental permitting, remediation, and mitigation
6. Non-Developer Driven Changes	Most proposals allow an increase to the construction cap for costs driven by changes from regulatory government agencies, local utilities, MISO, and Force Majeure.

Source: MISO, Duff Coleman Selection Report, December 20, 2016, p. 27.

As listed above, some proposals contained cost caps with several exemptions or exceptions. Such exclusions can have a significant impact on a project's final cost, often include issues for which it is difficult to accurately predict costs, and substantially mitigate the developer's risk. For example, a project routing change exemption significantly reduces risks for developers who propose a cap on total investment costs or revenue requirements. Failing to price the risk associated with significant cost changes could allow the developer to submit proposals with seemingly low and/or aggressive cost targets that may not materialize if the project experiences significant cost escalations (e.g., unexpected route changes).

The Designated Entity Agreement ("DEA") between PJM and Northeast Transmission Development ("NTD"), a subsidiary of LS Power, for the Artificial Island project provides an illustrative example. This developer agreement includes a non-standard provision that appears to establish a cap on "Construction Costs" at the lesser of actual costs or a Construction Cost Cap amount of $146 million, adjusted for escalation using the Handy-Whitman Index. However, the agreement contains several exceptions - including project scope changes directed by PJM (project scope is a significant cost driver) - to its construction cost cap:

> Schedule E Section (e)
>
> "Excluded Costs" means (i) any taxes, (ii) any financing costs, including any approved return on equity, Allowance for Funds Used During Construction, or similar allowance or financing cost or charge earned or accrued in connection with the Project during the period of development and construction of the Project (or thereafter), (iii) any costs and expenses associated with any PJM directed additions to or modifications of the Scope of Work (but only if and to the extent such costs and expenses are in excess of the costs and expenses that would have been incurred but for such addition to or modification of the Scope of Work), (iv) any costs and expenses incurred as a result of an Uncontrollable Force (but only if and to the extent such costs and expenses are in excess of the costs and expenses that would have been incurred but for such Uncontrollable Force) and (v) any costs and expenses associated with the operation and maintenance of the Project.[27]

Schedule E allows for cost recovery in excess of the stated cap under several conditions, many of which are classified as Force Majeure (or Uncontrollable Force).[28] This "out" may be a commonplace in other Developer Agreements as well. In addition to the Force Majeure provision, the language quoted above also includes exceptions for all taxes, changes directed by PJM, and operation and maintenance costs.

FERC accepted all terms and conditions contained in the DEA between PJM and Northeast Transmission Development.[29] These exclusions could create the impression that the winning project in a given solicitation has low costs, when in reality the final project costs can be higher than the winning developer's bid and potentially higher than the final costs of a competing project that was not selected. With such cost cap exclusions, some of the risks of cost overruns rest with the customer, not the winning developer. And, not only do risks remain on the customer, but incentives are created for developers to remove the cost of that risk (contingencies) from project bids, artificially deflating estimated costs.

Additionally, some of the cost caps reviewed by Concentric only cap transmission revenue requirements during a subset of the project's operational life. Such cost caps may unintentionally create incentives for developers to defer necessary investment in order to keep rates below the applicable cap. Several solicitations held to-date have included revenue requirement caps. For example, in the Suncrest project in CAISO, NextEra[30] agreed to a project construction cost cap of $42,288,000 in 2015 dollars, and an operation and maintenance ("O&M")

27 Artificial Island PJM DEA Proposed Agreement, Schedule E, Section 1.2e.
28 Artificial Island PJM DEA Proposed Agreement, Schedule E, 1.2g.
29 *PJM Interconnection, L.L.C.*, 154 FERC ¶61,054, Order Accepting Proposed Agreement, (January 29, 2016).
30 CAISO, Suncrest Selection Report, http://www.caiso.com/Documents/SuncrestProjectSponsorSelectionReport.pdf

cost cap of $360,000 per year for the first five years of the project's operational life.[31] NextEra's winning bid in MISO for the Hartburg-Sabine line also included a cap on O&M for the first 10 years of the project.[32]

Capping items like O&M over a portion of a project's life may not be in the best interest of customers; it can create incentives to spend less on O&M to maintain a desired return, which can impair reliability and may significantly increase O&M costs in later years if materials fail. Furthermore, capping O&M expenditures in the first years of a project's life does not necessarily induce savings as O&M costs tend to be lowest in early project years given that equipment is relatively new. O&M costs tend to increase as the project ages, and the O&M related cost caps in the winning bids reviewed in Appendix C do not cap O&M late in a project's operational life.

Finally, cost caps can also be complex and potentially difficult to enforce. Even if there were an effective and transparent mechanism to monitor the cost caps of a given project, enforcement could be challenging because the cost caps are included in an agreement that the winning developer executes with the ISO/RTO (e.g., Approved Project Sponsor Agreement in CAISO or Designated Entity Agreement in PJM) but the project's annual revenue requirement and associated transmission rate is approved by FERC. In a recent paper regarding solicitations for transmission projects, Paul Joskow referred to this ambiguity as an "institutional gap."[33]

3.2. Brattle's Cost Savings Estimates are Flawed

3.2.1 Inaccurate Lower Bound Savings Estimate

Table 8 above summarizes the total number of solicitations that have been carried out as of April 2019 in the ISOs/RTOs versus the number of solicitations the Brattle Report focuses on to estimate savings. The experience with solicitations for new transmission projects in the ISOs/RTOs has been limited, particularly outside of CAISO and PJM.[34] The Brattle Report produced both lower bound and upper bound savings estimates for these solicitations.

This Subsection examines the "reference costs" Brattle used to estimate a lower bound on the savings Brattle claims have resulted from the solicitations.[35] To estimate savings from each solicitation, the Brattle Report compared the winning bid to a benchmark referred to as a "reference cost". The report used either an ISO planning estimate (CAISO, MISO, or SPP) or an incumbent TO bid (PJM or a third-party estimate of that bid in NYISO) as reference costs for the solicitations. Use of this reference cost methodology appears to have resulted in the Brattle Report not estimating savings for solicitations awarded to incumbent TOs in PJM and NYISO.

---

31 Approved Sponsor Agreement Between NextEra Energy Transmission West, LLC and California Independent System Operator Corporation, Exhibit NEET WEST-10, filed August 31, 2015 in CPUC Application No. A.15-08-027, http://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A1508027/520/186580410.pdf, p. 43.

32 MISO, Hartburg-Sabine Selection Report, November 27, 2018, p. 24.

33 Joskow, Paul, Competition for Electric Transmission Projects in the U.S.: FERC Order 1000, Revised March 16, 2019, p. 22.

34 CAISO plans to hold solicitations for the Gate 500 kV Dynamic Reactive Support and Round Mountain Dynamic Reactive Support projects in 2019.

35 Brattle Report, figures 18 and 19. Brattle uses all 14 projects to estimate upper and lower bounds but presents results for only 13 of the projects in figure 19, presumably because the Walkemeyer and Gates Gregg projects were delayed.

However, if a solicitation in and of itself produces the savings the Brattle Report claims, the nature of the winning developer, incumbent or non-incumbent, is irrelevant. As described further below, using the report's reference cost methodology would have resulted in "negative savings" for the AP South solicitation in PJM.

Table 11: Brattle Report Estimated Range of Potential Savings from ISO/RTO Solicitations

	ISO or Incumbent Estimated Cost ($ million)	Winning Developer's Project Cost ($ million)	Lower Bound Savings Estimate (%)	Upper Bound Savings Estimate (%)
CAISO	$1,180	$833	29%	50%
ISONE	$n/a	$n/a	n/a	n/a
MISO	$181	$154	15%	28%
NYISO	$232	$181	22%	22%
PJM	$692	$280	60%	67%
SPP	$17	$8	50%	58%

Source: Brattle Report, April 2019, Figure 18, p. 41, see also Figure 19, p. 43.

The Brattle Report stated that it produced lower bound savings estimates by comparing the winning bid to either the ISO planning-level estimate for the project (CAISO, MISO, and SPP), or the lowest cost incumbent bid (PJM and NYISO).[36]

Given the nature of transmission project planning-level estimates discussed in Section 2, in our view, Brattle's lower bound savings estimates for the CAISO, MISO, and SPP solicitations are unsound. As discussed in Section 2 above, the precision of transmission project cost estimates increases as a project progresses through the development process and more information about project costs becomes available. Early planning-level estimates produced by the ISO/RTO are expected to differ significantly from the final project's costs because the ISO/RTO estimate is developed at a high level with general rather than specific estimates about the costs of various project components.

Therefore, comparing an early stage ISO/RTO planning-level estimate to the developer's fully developed project bid in a solicitation, as Brattle did for CAISO, MISO, and SPP, does not demonstrate the expected savings from conducting a solicitation compared to using another process. Instead, the Brattle Report's method provides an estimate of the accuracy (or inaccuracy) of the ISO/RTO's planning-level estimate. Furthermore, Brattle's use of the ISO/RTO planning estimate as a reference cost does not reflect the benefits from competition because the winning bidder is not competing with the ISO/RTO planning estimate but with the other bidders. As such, it would be more appropriate to compare the winning bid in a given solicitation to the bids of its competitors. Unfortunately, this information was not publicly available for CAISO.

36 Brattle Report pp. 28-29.

The Brattle Report claims that the 10 solicitations in CAISO produced savings of at least 29%.[37] Concentric reviewed the winning bids and CAISO planning level estimates Brattle used to produce this estimate and confirmed that Brattle used the high end of CAISO's planning level estimate for each solicitation when the CAISO estimate was a range (i.e., low and high cost estimates). Brattle's use of the high end of the CAISO planning-level estimates maximized the CAISO savings estimates. As described further in Appendix A, Concentric attempted to recreate Brattle Report's savings estimates of 7 of the CAISO solicitations and determined that using the low end of the CAISO planning-level estimate for each project yields "savings" of 3% and using the high end yielded estimated savings of 26%.[38]

MISO has conducted two solicitations for new transmission projects and the Brattle Report claims that these solicitations produced savings of at least 15%.[39] The Duff-Coleman solicitation was awarded to Republic Transmission, LLC, a partnership between Big Rivers Electric Corporation and LS Power, with a $49.8 million bid that was 15% below MISO's $59 million planning-level estimate.[40] The Hartburg-Sabine solicitation was awarded to NextEra for $103.9 million, which was also 15% below the MISO planning-level estimate.[41] Because they are based on MISO planning-level estimates, we find that Brattle's lower bound savings estimates for the MISO solicitations suffer the same flaws as the CAISO estimates.

SPP conducted one solicitation for the Walkemeyer project and the Brattle Report estimated savings of 18% from this solicitation that was awarded to Mid Kansas Electric Company.[42] Brattle's lower bound savings estimate from this solicitation was based on SPP's planning-level estimate for the Walkemeyer project and thus, in our view, flawed for the reasons described above. Brattle's estimated savings for this solicitation is included in Figure 18 of the Brattle Report but not in Figure 19, which summarizes the upper and lower bound savings estimates by ISO/RTO, presumably because the Walkemeyer project was canceled due to declining load projections.

The methodology the Brattle Report used to estimate cost savings from a solicitation in PJM is also flawed. Unlike CAISO, MISO, and SPP, PJM and NYISO employ a "sponsorship model" to solicit alternative transmission solutions during their regional planning processes. As such, PJM and NYISO do not release ISO/RTO planning-level estimates before each solicitation. Rather than solicit proposals for a specific transmission project (e.g., new substation), PJM and NYISO issue a more general transmission "need" and bidders submit potential solutions to satisfy that need.

37 Brattle Report, Figure 19, p. 43.

38 See the CAISO section of the Appendix C for more details about the transmission solicitations in CAISO. Note that Concentric was not able to confirm the cost of the winning bid for three of the 10 CAISO solicitations.

39 Brattle Report, Figure 19, p. 43.

40 MISO Duff-Coleman Selection Report, p. 38.

41 Brattle Report, Table 7. Hartburg-Sabine Selection Report, p. 5.

42 Brattle Report, Figure 18, p. 41. As noted above, Brattle excludes its savings estimates for the Walkemeyer project from Figure 19, presumably because it was canceled.

In PJM, bidders are generally not restricted as to the scope of the proposals they submit in response to PJM (e.g., PJM could receive proposals that range from battery storage to greenfield transmission lines). PJM publishes the project costs from the submitted proposals, so it is possible to compare the bids with each other. However, this comparison is not very informative for the purposes of estimating cost savings from the solicitation because the scopes of the projects may be vastly different, which means they have different costs and benefits. Furthermore, the proposals submitted by developers do not include the full cost of integrating the project with the PJM system. Unlike a project-based solicitation, where project integration costs across proposals are generally the same because the ISO/RTO has defined the project scope, the integration costs of proposals submitted in a sponsorship model solicitation can differ significantly. As such, the stand-alone developer bids in each proposal do not constitute the full costs of that proposal and the proposals cannot be compared with one another without also considering integration costs.

The Artificial Island solicitation attracted a variety of projects to address the identified needs; the proposed costs of those projects ranged from the low $100 million range to $1.5 billion. Brattle compared two competing bids to estimate a lower bound savings estimate of 60% (or $412 million) for the Artificial Island solicitation.[43] However the Brattle Report neglects to mention that the bids were from different points in time and for different project scopes. The Artificial Island solicitation was particularly complex. PJM first held a solicitation window for the project in 2013. PJM subsequently issued a supplemental solicitation in 2014. Prior to awarding the final project, PJM changed the project scope, the route and the RFP itself.

Concentric identified the sources of the data the Brattle Report used to estimate the purported savings for the Artificial Island solicitation. Brattle compared the costs of the winning bid, a proposal submitted by LS Power (though changed by PJM), to the costs of a project submitted by PSE&G at the very beginning of the solicitation process.[44] This comparison is highly problematic and does not constitute a meaningful estimate of cost savings from the Artificial Island solicitation. In fact, because of all of the changes that PJM made during the 4-year pendency of the solicitation process, the ultimate LS Power "proposal" was not really its proposal at all, as the winning bid had a different terminus point from the one LS Power initially proposed, and PJM had in fact changed the RFP itself.[45]

The Brattle Report did not use the AP South solicitation to estimate savings from solicitations in PJM despite the fact that the AP South solicitation was awarded to a non-incumbent – Transource, an affiliate of AEP. The Brattle Report estimates for PJM may have excluded the AP South solicitation from its cost savings estimate because the Transource project was not the lowest cost bid. As such, using the report's methodology to

43 Brattle Report, Figure 13, p 32.

44 PJM Interconnection, Artificial Island Project Recommendation White Paper (July 29, 2015) at p. 12 (Table 2.1). The Brattle Report appears to have used PSE&G's $692 million proposal, submitted in 2013, for project "P2013_1-7E", that included New Freedom-Deans 500 and Salem - Hope Creek 500 kV lines as major components.

45 See Appendix C for more details on the information used in the Brattle Report to estimate savings from the Artificial Island solicitation.

estimate savings for this solicitation would have resulted in a negative savings estimate. The fact that the lowest cost bidder wasn't selected in the AP South solicitation doesn't necessarily mean the solicitation wasn't worthwhile. As described further in Appendix C, the PJM Board selected the Transource proposal because PJM staff found that the proposal had many desirable attributes and a favorable estimated cost-benefit ratio.[46]

NYISO has carried out two solicitations for new transmission projects – Western NY and AC Transmission. The Brattle Report only used a lower bound savings (22%) for the Western NY solicitation.[47] The report did not estimate savings for the AC Transmission solicitation, presumably because one segment of the solicitation, which had two segments total, was awarded to an incumbent TO.

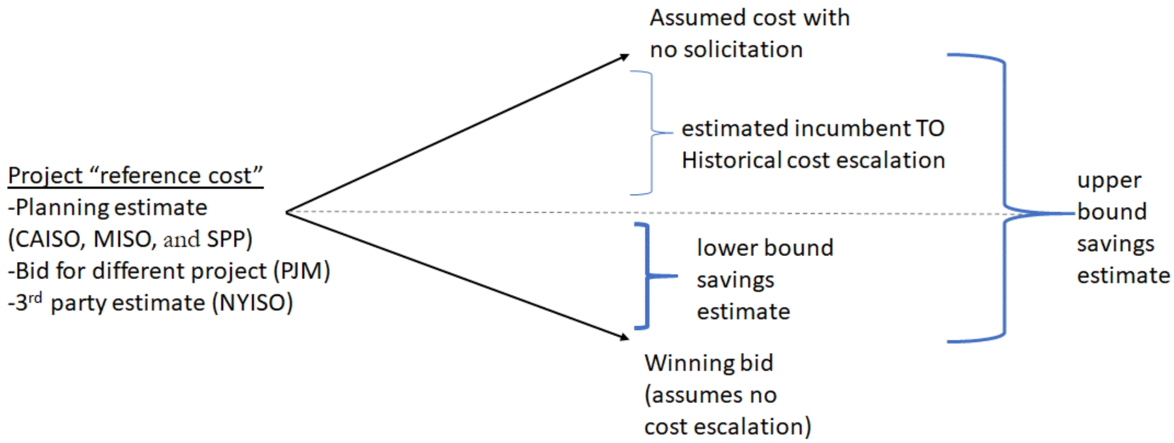
NYISO does not publicly release the costs contained in either the winning bid or bids that were not selected. Instead, NYISO releases project cost estimates produced by a third-party independent consultant based on the projects proposed in the solicitation. The Brattle Report compared these third-party engineering estimates and claimed that the difference between the estimates for two of the Western NY bids – one from two incumbents and another from a non-incumbent – represented savings from the Western NY solicitation.[48] It is not possible to determine how these third-party estimates compare to the actual bids submitted, so the Brattle Report's method to estimate savings from Western NY solicitation (22%) is highly speculative. Furthermore, given that NYISO uses a sponsorship solicitation model, the two proposals compared had entirely different scopes and differed on many dimensions other than cost, so limiting the comparison to third-party estimates of the two proposals' costs alone is not informative.

3.2.2 Methodologically Flawed Upper Bound Savings Estimate

This Subsection addresses the Brattle Report's upper bound savings estimates. We reviewed the upper bound savings estimates in the report and found that they were based on a methodologically flawed approach and used inaccurate assumptions about the historical cost escalations of incumbent TO projects in each ISO/RTO. Figure 3 presents a schematic that explains how Brattle produced its upper and lower bound savings estimates for the solicitations.

[46] See e.g., PJM White Paper, Transource Independence Energy Connection Market Efficiency Project, November 15, 2018.
[47] Brattle Report, Figure 18. *See also* Table 12.
[48] See Appendix C for further details.

Figure 3: Brattle Report Method for Estimating Upper and Lower Bound Savings from ISO/RTO Transmission Solicitations



As described in Subsection 3.2.1, the Brattle Report determined lower bound savings estimates by comparing the winning bid (with no cost escalation) with either an ISO/RTO planning-level estimate or the lowest cost of a competing incumbent TO bid (or third-party estimate of that bid in NYISO). Upper bound savings estimates were determined by inflating the ISO/RTO planning-level estimate or incumbent TO bid by the inaccurate "average historical cost escalation" figures discussed in Section 2.

The Brattle Report states that its upper bound savings estimates for the solicitations accounts for the fact that the final costs of the projects can escalate above the winning bids.[49] As the Brattle Report notes, "the final costs of the competitively-awarded transmission projects may similarly increase beyond their proposed costs as some of the proposed project costs are indexed to inflation and as developers are able to make certain adjustments as they complete their final routing, siting, and construction."[50] Thus, as discussed in Subsection 3.2.1, even if the winning bid has a cost cap or caps, the final costs of a transmission project awarded through a solicitation can exceed the original submitted bid.

The Brattle Report asserts that the upper bound savings estimates account for the possibility of project cost escalation.[51] However, rather than applying its "average historical cost escalation" estimates – which as discussed in Section 2 are significantly overstated – to the winning bids themselves, Brattle inexplicably applies its average historical cost escalation estimate to each project's "reference cost" (i.e., the ISO/RTO planning-level estimate or a competing incumbent TO bid).

As shown in Figure 3 above, Brattle then compares the escalated reference cost – a figure the Brattle Report refers to as the "Expected Cost if Competitive Projects were not subject to Competition"[52] – to the winning bid

---

49 Brattle Report, p. 42.

50 Brattle Report, p. 40. The "adjustments" Brattle referred to here are presumably the exclusions to the cost caps contained in the winning bids, which are described in Subsection 3.1.

51 Brattle Report, pp. 40-42.

52 Brattle Report, Figure 18, column 6.

with no escalation to produce an upper bound savings estimates for the solicitations in each ISO/RTO. This method is fundamentally flawed for two reasons.

First, Brattle applied its estimated cost escalation to the wrong figure, specifically the "reference cost" rather than the winning bid itself (i.e., the basis for Brattle's claimed savings in the first place). As noted in Section 3.1 and in the Brattle Report, the final cost of a project awarded in a solicitation can exceed the winning bid, even if the bid included a cost cap. It is not clear what the upper bound estimate is supposed to represent because the figure Brattle uses bares no relation to the winning bid, and simply assumes, without any basis, that the ISO/RTO planning estimate or competing TO bid will incur significant cost escalation. Furthermore, this upper bound estimate assumes that the project will only experience cost escalation if it is developed by an incumbent and will not experience *any* cost escalation if developed by a non-incumbent. This assumption is clearly false because any project developer – incumbent or not – faces development risks due to factors beyond its control (e.g., routing changes, other regulatory or environmental permitting issues, input cost changes for greenfield projects, equipment cost changes, inflation, etc.).

Comparing Brattle's inflated reference cost to the winning bid with no cost escalation does not provide a meaningful or informative upper bound estimate of savings and does not account for potential project cost escalation. This is evident by the fact that the Brattle Report's attempt to account for project cost escalation actually *increases* the estimated savings from the solicitations. It defies basic logic to claim, as Brattle does, that the savings from a solicitation would *increase* if the project's costs were to escalate above the winning bid.[53] To properly account for potential project cost escalation, the Brattle Report should have applied a cost escalation estimate to the winning bid itself. Such an approach would have *reduced* rather than *increased* Brattle's estimated upper bound savings from the solicitation.

The second flaw with the upper bound savings estimates is that the Brattle Report employed its inaccurate and overstated estimates of the cost escalation experienced by incumbent TOs to estimate this upper bound. We show in Section 2 that the report's estimates of incumbent TO cost escalation is vastly overstated and inconsistent with empirical evidence. Thus, in addition to using a methodologically flawed approach to account for cost escalation, Brattle's upper bound estimates also rely on inaccurate assumptions about incumbent TO projects.

Given these flaws, we find the lower and upper bound savings estimates in the Brattle report to be without merit. These estimates do not demonstrate significant savings as claimed in the Brattle Report and should not be relied upon for decision making purposes. As noted in Section 3.1, it is too soon to assess the cost impacts of the solicitations because the final cost impacts are only known for one of the 15 projects.

[53] Brattle Report, p. 42.

4. Transmission Solicitations are Time and Resource Intensive

This Section describes some features of transmission solicitations that are important for decision makers and other stakeholders to consider before expanding solicitations beyond their current scope. The first consideration is the type of cost caps included in solicitations and the extent to which they reduce costs. As described above, Concentric found that the Brattle Report fails to demonstrate that the 15 solicitations its savings estimates are based on have produced any savings. A second consideration is the "administrative cost" of conducting a solicitation for a new transmission project. A third consideration is bidder preparation costs.

The Commission stated that one of the core objectives of the Order No. 1000 requirements was to achieve more efficient or cost-effective regional transmission planning.[54] The Commission did not specifically require regional transmission planners to conduct solicitations in the regional planning process.[55] Instead, it chose to afford ISOs/RTOs flexibility in implementing the Order No. 1000 requirements, based on the expectation that an open and transparent process that involved multiple entities and considers the transmission needs of all customers would help regional transmission planners identify solutions that are more efficient or cost-effective.[56] A narrow focus on solicitations for transmission development ignores the overriding purpose of Order No. 1000, which was to ensure all customers' needs were considered and there was an opportunity for more efficient or cost effective solutions to be identified.

All six FERC-jurisdictional ISOs/RTOs chose to conduct solicitations in their regional planning process, and some ISOs (e.g., CAISO) conducted solicitations before the Commission issued its third and final order on the Order No. 1000 requirements. Given that Brattle and others have advocated expanding the scope of solicitations in these ISOs/RTOs, it is important to examine the resources required to conduct these solicitations. These resources include, but are not limited to, the time it takes to conduct the solicitations, ISO/RTO costs to issue the solicitations, qualify bidders, review proposals, and select a winning proposal ("ISO/RTO implementation costs"), and bidder preparation costs. We refer to these as "administrative costs".

This analysis is not intended to claim or otherwise argue that solicitations for new transmission projects are never worthwhile. Rather, the intent of this Section is to highlight the resources involved in conducting the solicitations that have occurred to-date and some of the complexities experienced with some of the solicitations. This information should enable policymakers and the public to make more informed decisions about whether to expand these solicitations.

The evidence below, which is based on publicly available information, demonstrates that conducting solicitations in ISO/RTO regional transmission processes is a time and resource intensive process. The fact that conducting a solicitation involves costs does not in and of itself mean that solicitations are not worthwhile.

---

54 Order No. 1000, at P 2.
55 See Appendix D for additional details about the Order No. 1000 requirements and associated ISO/RTO compliance filings.
56 See e.g., Order No. 1000, at P 11.

Rather, it is generally worthwhile to conduct a solicitation for projects where the benefits expected from conducting a solicitation verses an alternative process (e.g., designating a specific developer to construct the project) exceed the costs of conducting that solicitation.

The Commission implicitly made such calculations in Order Nos. 1000, 1000-A, and 1000-B when it decided to exempt certain types of transmission projects from the Order No. 1000 requirements. For example, the Commission recognized that timeliness is a factor that must be considered in the transmission planning process and approved time-based exemptions from the Order No. 1000 requirement to remove the federal Right Of First Refusal ("ROFR") in PJM, ISO-NE, and SPP for certain new transmission projects needed to address reliability.

Three types of administrative costs of conducting a solicitation – time-related costs, ISO/RTO implementation costs, and bidder preparation costs – are discussed in turn below.

4.1. Time-Related Costs

Time is arguably the most expensive resource associated with transmission solicitations. It is inherently difficult to assign a monetary value to time, and this report makes no attempt to do so. Instead, we summarize the number of days it took to carry out each solicitation, information the reader can use to make his or her own evaluation. Solicitations take time to prepare, review, issue, and administer. Bidders also spend time and resources preparing bids, and the ISO/RTO staff (which may include third party consultants) must review and ultimately select among the competing proposals. In addition, time delays may impact project implementation, denying customers the benefit of the project.

Table 12 summarizes the time involved to conduct the solicitations that have been carried out in Order No. 1000-compliant ISO/RTO regional planning processes as of the writing of this report. The time involved in conducting the solicitation and selecting a winning proposal delays a given project's implementation, which also delays the benefits (e.g., lower congestion costs, increased reliability, etc.) of the project.

Table 12: Time Involved in Transmission Solicitations

Project	Date Need Identified	Solicitation Window	Date of ISO/RTO Board Approval	Days Between Identification and Board Approval
Imperial Valley	CAISO 2012-2013 Transmission Plan, Mar. 20, 2013	Dec. 20, 2012- Feb. 19, 2013	Jul. 11, 2013	113
Gates-Gregg		Apr. 1- Jun. 3, 2013	Nov. 6, 2013	231
Sycamore-Penasquitos		Apr. 1 - Jun. 3, 2013	Mar. 4, 2014	349
Suncrest	CAISO 2013-2014 Transmission Plan, Jul. 16, 2014	Apr. 16 - Jun. 16, 2014	Jan. 6, 2015	174
Delany Colorado River		Aug. 19 - Nov. 19, 2014	Jul. 10, 2015	359
Estrella		Apr. 16 - Aug. 18, 2014	Mar. 11, 2015	238
Harry Allen to Eldorado		Jan. 30 - Apr. 30, 2015	Jan. 11, 2016	544
Miguel†		Apr. 16 - Jun. 16, 2014	Sep. 9, 2014	55
Spring		Apr. 16 - Aug. 18, 2014	Mar. 11, 2015	238
Wheeler Ridge		Apr. 16 - Aug.18, 2014	Mar. 11, 2015	238
Duff-Coleman	MISO MTEP-15, Dec. 1, 2015,	Jan. 9 - Jul. 6, 2016	Dec. 20, 2016	385
Hartburg-Sabine	MISO MTEP-17, Dec,1, 2017	Feb. 6. - Jul. 20, 2018	Nov. 27, 2018	361
Walkemeyer	SPP 2015 ITP, Jan. 20, 2015	May 5- Nov. 2, 2015	Apr. 12, 2016	448
Artificial Island‡	PJM 2012 RTEP, Feb. 28, 2013	Initial: Apr. 29 - Jun. 28, 2013 Supplemental: Aug. 12- Sep. 19, 2014	Initial: July 29, 2015 Revised: April 6, 2017	1,498
AP South	PJM 2013 RTEP, Feb 28, 2015	Oct. 30, 2014- Feb. 27, 2015	Aug. 9, 2016	893
NY Western Public Policy	NYISO - July 20, 2015 NYPSC Order	Nov. 1, 2015- Jan 1, 2016	Oct. 17, 2017	820
AC Transmission+	NYISO - Dec. 17, 2015 NYPSC Order	Feb. 29, 2016- Apr. 29, 2016	April 8, 2019	1,208

† The Miguel solicitation had a single bidder – San Diego Gas & Electric.
‡PJM staff made an initial selection in the Artificial Island solicitation on Jun. 16, 2014. The PJM Board made an initial selection on Jul. 29, 2015, suspended the project in August 2016 for further consideration, and approved a revised scope in April 2017. See the case study in Subsection 4.2 for more details.
+The NYISO Board revised NYISO staff's recommendation for one segment of the AC Transmission solicitation

Once a need is identified, the next step is to solicit proposals, which are RFPs for specific projects under the project model (e.g., CAISO) and more broadly defined transmission needs under the sponsorship model (e.g., PJM). The next step is the solicitation window, which typically lasts between 60 and 120 days. As indicated in Table 12, the ISO/RTO may choose to amend the solicitation requirements, or seek additional information from bidders, which adds time to the solicitation window. Next, the ISO/RTO staff, sometimes with the help of independent consultants, evaluates the proposals according to the metrics specified in the tariff and prepares a recommendation. This selection process and the recommended selection (i.e., the winning proposal) are typically described in a selection report. ISO/RTO staff then submits the selection report and makes a formal recommendation to the ISO/RTO board. The board typically accepts staff's recommendation, although this is not always the case (e.g., the AC Transmission solicitation in NYISO).[57]

As shown in Table 12, solicitations in ISO/RTO regional planning processes with more than a single bidder can take a significant period of time, ranging from 113 to 1,498 days. The longest solicitation was for Artificial Island in PJM, where PJM staff made significant amendments to the proposed project scope during the staff evaluation phase and subsequently amended the submitted proposals.[58] The case study below describes the issues PJM and its stakeholders experienced during the Artificial Island solicitation.

Artificial Island Case Study

PJM identified system performance and voltage issues in the "Artificial Island" area surrounding the Hope Creek and Salem nuclear units in New Jersey during its 2012 and 2013 transmission planning cycle. On April 29, 2013, PJM issued a problem statement and opened a 60-day proposal window to address the Artificial Island issues. Bidders submitted 26 separate proposals with cost estimates ranging from approximately $100 million to $1.55 billion for a wide array of projects including, but not limited to, greenfield transmission lines, new substations, system reconfigurations, and dynamic reactive devices.[59] At a Transmission Expansion Advisory Committee (TEAC) meeting in May 2014, PJM staff explained to stakeholders that it changed technical specifications within the proposals.[60]

In a June 2014 presentation to the TEAC, PJM staff indicated that it would recommend that the PJM Board approve the PSE&G proposal, which involved a 500 kV transmission line between Hope Creek and Red Lion 500 kV substations and associated substation work.[61] After the close of the bidding window, LS Power amended its bid to include a cost cap. Additional stakeholders also submitted comments on PJM staff's recommendation. As a result, the PJM Board decided to defer action on Staff's recommendation. The PJM Board also sought further information, through a supplemental proposal, from a shortlist of projects.[62]

On August 12, 2014, PJM requested supplemental information on the final terms of the proposed project costs from the shortlisted bidders and asked for responses by September 12, 2014.[63] In August 2014, PJM also requested the assistance of FERC's Alternative Dispute Resolution office to assist in PJM's discussions with the shortlisted bidders. PJM announced at an April 2015 TEAC meeting about Artificial Island that it would recommend that the PJM Board approve the LS Power proposal, which also required integration work that would be carried out by Public Service Electric & Gas (PSE&G) and Delmarva Power Light. PJM summarized its revised recommendation in a July 29, 2015 whitepaper.[64]

---

57 See Appendix C for details of NYISO's AC Transmission solicitation.

58 See Appendix C for details of PJM's Artificial Island solicitation.

59 PJM Interconnection, Artificial Island White Paper, July 29, 2015, at 11.

60 In an Answer to a complaint filed by PSE&G, PJM explained that the modifications included: (1) the construction of a static VAR compensator (SVC), as proposed by some bidders, at a substation where it would be built and owned by PSE&G, in order to improve stability performance; (2) the relocation of the connection point within a substation in two proposals to eliminate a critical fault; (3) the removal of breaker schemes proposed in some proposals in favor of a ring bus modification proposed by one of the bidders; and (4) the removal of certain transmission lines from several proposals because, with the construction of a SVC, the additional facilities were not needed to pass applicable reliability criteria testing and therefore their removal would reduce costs and improve constructability. Public Service Electric and Gas Company, Order Denying Complaint 151 FERC ¶ 61,229 (June 16, 2015) at n. 28 (citing PJM's March 11, 2015 Answer at 12-13).

61 PJM Interconnection, Artificial Island Recommendation, at 36, presented at the June 16, 2014 TEAC meeting. As explained above, PJM ultimately changed its mind and removed the SVC from the project scope when it awarded the revised project to LS Power in response to concerns about total project cost.

62 PJM Board Letter to TEAC members, July 23, 2014.

63 PJM, Artificial Island Supplemental Proposal Request, August 12, 2014.

64 PJM, Artificial Island Recommendation White Paper, July 29, 2015.

The PJM Board approved the Artificial Island Project in July 29, 2015. However, PJM initially underestimated the cost of integration work at the terminus PSE&G substation. PJM's revised estimates raised the estimated total cost, reflecting inclusion of the integration costs with the PSE&G system, of the LS Power Proposal.[65] This cost increase, in part, led the PJM Board to suspend the project in August 2016, and the Board directed PJM staff to conduct a more comprehensive analysis. During the reevaluation, PJM staff eliminated certain project elements (including the construction of an SVC) to lower cost, amended its RFP to reflect the elimination of these project elements and changed the terminus point of the new line from the Salem Substation to the Hope Creek Substation.[66] As a result, the project ultimately awarded was substantially different from both the PSE&G project that was initially recommended by PJM Staff in 2014 and the PJM-Board approved project in 2015 that was awarded to LS Power. The table below, an excerpt from a March 2017 PJM staff presentation to the TEAC, shows how the cost estimates from the Artificial Island project changed over time as PJM changed the project scope and updated cost estimates for various components of the proposal.

Cost Estimates of Selected Artificial Island Project ($ millions)

Project Component	Initially approved project scope (July 2015)	Cost Update (Feb. 2016)	Final approved project scope (Mar. 2017)
230 kV Line and Silver Run Substation	$146	$146	$146
Salem Interconnection	$61-74	$152	
Hope Creek 2B Interconnection			$132
OPGW	$25	$39	
New Freedom SVC	$38	$81	
DE Interconnection	$2	$2	$2
Project Total	$272-285	$420	$280

Source: PJM Interconnection, *Artificial Island*, presented at a March 3,2017 TEAC meeting, at 13.

On April 6, 2017 the PJM Board lifted the suspension on the Artificial Island project and approved PJM staff's recommendation to retain LS Power as the developer of the revised Artificial Island 230 kV transmission line under the revised project scope and route.[67]

Given the significant irregularities associated with this solicitation, it is not clear why the Brattle Report relied on the Artificial Island solicitation to draw any conclusions about the benefits of or cost savings of transmission solicitations. Indeed, we are surprised the report appears to present Artificial Island as a successful solicitation. In our view, the time required to conduct these solicitations (see Table 12) validates the Commission's findings in Order Nos. 1000, 1000-A, and 1000-B and in the ISO/RTO compliance filings that it may not be feasible to conduct a solicitation for a transmission project that is needed within a fairly short timeframe (e.g., reliability project).[68]

---

65 PJM, Transmission Expansion Advisory Committee Artificial Island Recommendations to the PJM Board, PJM Staff White Paper, April 5, 2017, p. 4.

66 PJM Press Release, PJM Board Lifts Suspension of Artificial Island, April 6, 2017.

67 PJM Board letter to PJM Stakeholders, April 6, 2017. This letter also noted the cost allocation issues associated with the project.

68 See e.g., *PJM Interconnection, L.L.C., et al.*, Order on Compliance Filings, 142 FERC ¶ 61,214 (Mar. 22, 2013) at P 247. Section 5 and Appendix E discuss Order No. 1000 precedent regarding transmission projects needed to address reliability.

4.2. ISO/RTO Implementation Costs

ISO/RTO staff time and resources represent another cost of conducting a solicitation. Specifically, the time, money, and resources spent preparing, issuing, reviewing and evaluating, and selecting a winning proposal. These costs are allocated to the bidders rather than to load, but they are still incurred and likely to be recovered from load and thus should be considered when evaluating whether to conduct a solicitation in the first place. Some ISOs/RTOs have documented the implementation costs incurred to conduct a solicitation while others have not. Publicly available information about these implementation costs is summarized in Table 13 below.

Table 13: Summary of ISO/RTO Costs Incurred to Implement Solicitations in Regional Transmission Planning Processes

Project/Window	ISO/RTO	Cost Incurred
Suncrest	CAISO	$260,572
Delaney to Colorado River	CAISO	$530,359
Estrella	CAISO	$206,104
Harry Allen to Eldorado	CAISO	$434,703
Wheeler Ridge Junction	CAISO	$151,179
Miguel*	CAISO	$15,056
Spring 230 kV Substation	CAISO	$165,912
Duff-Coleman	MISO	$1,331,940
Hartburg-Sabine	MISO	$1,137,240
Walkemeyer	SPP	$522,196
2016 Windows 1-3	PJM	$457,717
2016/17 Long Term Window	PJM	$902,115
2017 Window 1	PJM	$328,287

Notes: The accounting the ISOs/RTOs employed to produce these estimates is somewhat unclear and the ISO/RTO figures may include different cost categories. The Miguel solicitation had only one bidder. PJM costs only refer to proposal evaluation costs. See Appendix C for data sources.

The ISO/RTO's direct implementation costs alone should be considered to constitute a lower bound on the actual costs expended on competitive solicitations because several stakeholders, such as the bidders, incumbent TOs, and other interested stakeholders (e.g., load advocates, state regulators) also expend resources by participating in a competitive solicitation. There is also an opportunity cost of conducting a competitive solicitation because ISOs/RTOs generally have limited resources with an obligation to operate the system and administer markets as well as comply with FERC regulations. The CAISO implementation cost estimates in Table 13 appear quite conservative when compared to the costs incurred to conduct competitive solicitations in MISO and SPP. For example, CAISO carries out a process that involves the same general steps as MISO and SPP, where it first issues technical specifications and selection criteria prior to each solicitation, and subsequently prepares a selection report that describes how CAISO staff evaluated the proposals and selected a winning bid (CAISO selection reports are about 100 pages long).

MISO estimates that it incurred $1,331,940 to select the winning developer in the Duff-Coleman solicitation. MISO recovered these costs from the 11 bidders through a combination of an initial $100,000 deposit from each bidder and an additional invoice of $21,086. MISO estimated that about 26% of the Duff-Coleman solicitation implementation costs were associated with the cost estimate, while the balance of costs incurred were associated with issuing the RFP (13%), assessing the design (17%), project implementation (13%), operations & maintenance (16%) components of each proposal, and the administrative and management and selection report costs (15%).[69] MISO estimated a similar cost to conduct the Hartburg-Sabine solicitation.

After conducting the Walkemeyer solicitation, SPP and its stakeholders evaluated the competitive solicitation to identify "lessons learned". SPP explained in a filing with FERC the costs SPP incurs to "contract, retain, and train" the group of third-party industry experts it hires to evaluate the proposals submitted in competitive solicitations – referred to as the Industry Expert Panel. SPP estimated it incurs a minimum of $300,000 per solicitation to select and retain the Industry Expert Panel.[70] Furthermore, SPP's $300,000 minimum cost estimate does not include any recoverable SPP time involved in selecting and retaining the Industry Expert Panel.[71]

SPP reported that the full cost of administering the Walkemeyer solicitation was $522,196, consisting of $87,468 for SPP staff expenses, $322,058 for the Industry Expert Panel, and $112,670 for the Industry Expert Panel consultant.[72] On September 20, 2017, SPP referenced the Walkemeyer review costs it incurred in a proposal with FERC to revise its tariff and only hold a competitive solicitation through the SPP regional transmission planning process for projects with an estimated cost of at least $3 million. The Commission rejected SPP's proposal without prejudice on grounds that SPP failed to sufficiently explain the proposed $3 million threshold or demonstrate that it was just and reasonable and not unduly discriminatory or preferential.[73]

Finally, ISO/RTO presentations and stakeholder materials suggest that it can be difficult for ISO/RTO staff to evaluate and compare multiple proposals that contain various cost caps. For example, PJM notes that each

---

69 MISO, ISO's Planning Advisory Committee Competitive Transmission Monthly Update, March 15, 2017, at 6, available at https://cdn.misoenergy.org/20170315%20PAC%20Item%2003b%20CTA%20Update89803.pdf. See also https://cdn.misoenergy.org/Incurred%20Costs%20-%20Duff-Coleman%20EHV%20345kV82322.pdf.

70 SPP, Order Rejecting Tariff Revisions, 161 FERC ¶ 61,199 (November 17, 2017), at P 6. See also SPP Transmittal Letter, Docket No. ER17-2523, p. 4-5.

71 SPP Transmittal Letter, Docket No. ER17-2523 (Sept. 20, 2017) p. 4-5.

72 SPP Transmittal Letter, Docket No. ER17-2523 (Sept. 20, 2017) p. 4-5 citing the SPP July 7,2016 Strategic Planning Committee – Order 1000 Workshop Meeting Minutes, p. 33, available at https://www.spp.org/documents/40327/spc%20workshop%20minutes%2020160707.pdf

73 *Southwest Power Pool, Inc.,* Order Rejecting Tariff Revisions, 161 FERC ¶ 61,199 (November 17, 2017), at PP 10-13.

proposal from a given solicitation involves project-specific (e.g., constructability and associated risk factors), legal, and financial risks that must be evaluated and compared against other proposals. PJM plans to implement a new process to assess these risks and the new process will require PJM to hire independent consultants to conduct feasibility studies and a separate financial consultant to assess the proposals' financial risks. PJM states it will adjust its fee structure upward to account for these additional evaluation costs, which will be assessed to bidders.[74]

4.3. Bidder Preparation Costs

Bidders also incur costs to prepare proposals for ISO/RTO solicitations for new transmission projects. For example, Southwestern Public Service Company[75] sought a Declaratory Order from the Public Utility Commission of Texas to prevent SPP from issuing a competitive solicitation for the Potter – Tolk line because the company estimated it would cost at least $750,000 to respond to the solicitation.[76] Although the load does not pay these costs directly, they are still incurred by market participants and ought to be considered. Additionally, bidder preparation costs can be aggregated over time and converted into a regulatory asset that can later be recovered in transmission rates if the winning bidder becomes a transmission owner in a given ISO/RTO. For example, in March 2017 Republic Transmission, which won the Duff Coleman solicitation in MISO, petitioned FERC for certain transmission rate incentives related to the Duff-Coleman project, including the deferred recovery of prudently incurred pre-commercial costs through creation of a regulatory asset.[77] Bidder preparation costs are largely undocumented, but the limited publicly available information about such costs (e.g., Potter – Tolk line) suggests they are not trivial. The Brattle Report claims that these costs will decrease over time as bidders gain experience,[78] which may be true on a project-specific basis, but bidder preparation costs, which can involve detailed engineering estimates and securing financial guarantees, will never be driven to zero, and if solicitations expand so too will the number of bids.

---

74 *See e.g.,* PJM, Cost Containment Status and Next Steps, presented to the PJM Planning Committee on May 16, 2019.

75 Southwestern Public Service company serves retail electric customers in the Panhandle and South Plains areas of Texas (entirely outside of ERCOT) and in southeastern portions if New Mexico.

76 Joint Petition of Southwestern Public Service Company and Southwest Power Pool, Inc. for Declaratory Order, PUCT Docket No. 46901 (February 28, 2017) at p. 11, available at http://interchange.puc.texas.gov/Documents/46901_1_930801.PDF.

77 *Republic Transmission, LLC*, Order Granting Petition for Declaratory Order, 161 FERC ¶ 61,036 (October 6, 2017) at P 21.

78 Brattle Report, p. 39.

5. No Basis to expand Order 1000 solicitations

This section explores the regulatory implications of Brattle's proposal to expand solicitations for new transmission projects beyond the scope the Commission required when it issued Order No. 1000. Brattle's savings estimates simply assume that a significant expansion is feasible and the report states that "if only 25% of U.S.-wide investment was subjected to competition and competitively developed projects yielded 20% cost savings", customers would save between $4.4-$6.6 billion over five years.[79] Brattle also estimates that if solicitations were held for 33% of all U.S.-wide transmission investment, savings would increase to $6-9 billion over five years.[80] However, Brattle does not specify what types of new transmission projects would be included or how such an expansion would be carried out.

Another issue with the Brattle Report's claims that potential savings of up to $9 billion are possible is that Brattle applied its flawed historical cost escalation estimate to *all* transmission projects (or at the very least a much broader group of transmission project types). However, the types of projects that would necessarily be included in such an expansion – such as local reliability projects, asset management projects, and upgrades – generally face much lower cost escalation risks than the subset of incumbent TO projects that form the basis of the Brattle Report's estimates.

For example, Brattle's analysis of ISO-NE projects included only 14 major projects, many of which were greenfield projects. Greenfield projects face considerably more risk than the full gamut of transmission projects. For example, a relatively modest upgrade to an incumbent TO's substation does not generally involve risks associated with right-of-way and may not require a certificate of public need and necessity.

Significantly expanding the scope of transmission projects selected through solicitations to achieve the purported savings claimed in the Brattle Report, especially to 25% or 33% of total US investment, would also require a shift in FERC policy about regional and local transmission planning and would involve revisiting several key decisions in Order No. 1000, 1000-A, and 1000-B. An expansion would also be inconsistent with recent Commission precedent about local transmission planning where the Commission generally found that Order No. 890 does not require local transmission planning to be conducted through the ISO/RTO regional planning process.[81] The Brattle Report offers no basis to revisit this precedent and we find that the Commission's reasoning in the Order No. 1000 proceedings was sound and remains sound based on the experience of the solicitations held to-date. Expanding the scope of solicitations throughout the US would also likely require changes in state law with respect of rights of first refusal, which the Brattle Report acknowledges.[82] Given the issues Concentric identified in the Brattle Report, we find no basis to do so.

---

79 Brattle Report, p. 13.

80 Brattle Report, p. 13. Brattle assumes that US transmission investment over the next five years will be $100 billion and applies a 20% savings associated with conducting solicitations for new transmission projects. *See* Brattle Report, Figure 4, p. 13.

81 Monongahela Power Company et al. 164 FERC ¶ 61,217 (September 26, 2018), at P 13.

82 Brattle Report, p. 21.

The Brattle Report recommends that stakeholders and policymakers review and "potentially modify the criteria" used to determine the transmission projects eligible for solicitation under existing Order No. 1000-compliant planning processes in FERC-jurisdictional ISOs/RTOs. The report concedes that changing the scope of projects eligible for solicitation "may require modifying the requirements of Order No. 1000."[83] Given that the Commission has already found the regional transmission planning processes in these ISOs/RTOs to be just and reasonable and compliant with Order No. 1000, Brattle's recommendation would most certainly require revisiting some of the key findings in Order No. 1000, and recent Commission precedent about local planning.

In light of the Brattle Report's recommendation to expand the scope of transmission projects in ISO/RTO regional planning processes that are eligible for competition, Concentric reviewed the rationale the Commission used in Order Nos. 1000, 1000-A, and 1000-B to determine the applicability of those reforms. We also analyzed the Commission's reasoning and determinations in the individual ISO/RTO compliance filing orders where the Commission determined that the current planning processes in the ISOs/RTOs are just and reasonable and comply with Order No. 1000 requirements. Our review of Order No. 1000 precedent is contained in Appendix E.

Based on this review, we found that the Commission consciously targeted Order No. 1000 reforms to apply to a subset of *new* transmission projects that were selected in a *regional transmission plan* for purposes of *regional cost allocation*.[84] We believe that the Commission's choice to exclude certain types of transmission projects from the requirements of Order No. 1000 was appropriate at the time and remains appropriate. Given the flaws we identified in Brattle's "cost savings" estimates, we do not believe Brattle has demonstrated that expanding the scope of the Order No. 1000 requirements would produce the savings Brattle claims. Nor are we persuaded that the Commission's determinations in the Order No. 1000 proceeding or the subsequent ISO/RTO compliance filings are no longer just and reasonable.

As discussed in turn below, and in further detail in Appendix E, Order No. 1000 requirements do not apply to certain categories of transmission projects: (1) upgrades; (2) local transmission projects with costs that are not shared regionally; and (3) certain reliability projects. Each category and the rationale the Commission used to exclude such projects from Order No. 1000 is discussed in turn below.

5.1. Upgrades

The Commission affirmatively found that certain Order No. 1000 reforms only apply to *new* transmission facilities selected in a regional plan for purposes of cost allocation, and not upgrades.[85] As such, under Order No. 1000 reforms, incumbent TOs could retain a federal ROFR to upgrade their own transmission facilities. For example, the Commission stated that the Order No. 1000 reforms "do not affect the right of an incumbent

83 Brattle Report, p. 22.
84 Order No. 1000, p. 1.
85 Order No. 1000 at P 319 and Order No. 1000-A at P 357. See also Order No. 1000-B at P 41.

transmission provider to build, own and recover costs for upgrades to its own transmission facilities".[86] The Brattle Report notes that, consistent with the Order No. 1000 reforms, upgrades are excluded from solicitations in current ISO/RTO regional planning processes but suggests that "a vague or overly broad application of this clause" or "favoring upgrades over potentially more valuable transmission…limits the region from realizing the additional cost-efficiencies" that the report claims are possible from solicitations.[87]

In fact, there are often many good reasons to pursue upgrades to existing facilities in lieu of building a new transmission facility, including lower costs, minimal impacts to customers and landowners, and more efficient siting and permitting processes. In addition, in Order No. 1000-A, the Commission explicitly defined an upgrade as an "improvement to, addition to, or replacement of a part of, an existing transmission facility" and clarified that the term upgrade does not refer to an entirely new transmission facility.[88] Based on our review of the ISO/RTO Order No. 1000 compliance filings, the Commission carefully reviewed the proposed ISO/RTO tariffs to ensure that the ISO/RTO tariffs defined the term upgrade in a manner consistent with the definition provided in Order No. 1000-A.

5.2. Local Projects

Brattle argues that the determination the Commission made in Order No. 1000 to exclude local projects from the reforms has "greatly limited the scope" of competition in MISO.[89] Brattle recommends reviewing this exclusion and others. However, Order No. 1000 did not require ISOs/RTOs to eliminate an incumbent TO's federal ROFR to construct "local transmission facilities," where the Commission defined a "local transmission facility" as a "transmission facility located solely within a public utility transmission provider's retail distribution service territory or footprint that is not selected in the regional transmission plan for purposes of cost allocation."[90] The Commission would have to revisit this precedent to adopt Brattle's recommendation, but the report provides no basis or evidence to do so.

The Commission would also have to revisit more recent precedent that was not related to the Order No. 1000 proceeding. In August 2018, the Commission addressed applicability of Order No. 890 and expounded upon its view of local versus grid expansion projects when it rejected a complaint filed by California parties ("CPUC *et. al.*") against PG&E. Specifically, the Commission found that PG&E's "asset management projects", which were local transmission projects that were not selected through CAISO's regional planning process and not allocated regionally, were not subject to Order No. 890 requirements because such projects did not expand the transmission grid.[91]

86 Order No. 1000 at P 319. See also Order No. 1000-A, P 426.
87 Brattle Report, p. 21.
88 Order No. 1000-A at P 426.
89 Brattle Report, pp. 20-21.
90 Order No. 1000 at P 63.
91 "[t]he transmission planning reforms that the Commission adopted in Order No. 890 were intended to address concerns regarding undue discrimination in grid expansion. Accordingly, to the extent that PG&E asset management projects and activities do not

In the same order, the Commission made a distinction between PG&E's asset management projects, which did not incrementally expand the grid but may incidentally do so, and grid expansion projects, which did incrementally expand the grid.[92] As such, expanding solicitations beyond the current scope (i.e., new transmission projects selected through a regional transmission plan for purposes of regional cost allocation) as Brattle suggests, would run contrary to recent precedent that found that local projects, such as asset management projects in PG&E, do not constitute grid expansion. Brattle also expressed concerns with the fact that some transmission investment occurs outside of the ISO/RTO regional planning process. The Commission's determination in the CPUC *et. al.* complaint suggests that the Commission finds such an arrangement just and reasonable, and compliant with Order No. 890.

The Brattle Report's proposal to require that a greater proportion of transmission projects be coordinated through the ISO/RTO regional transmission planning process is also inconsistent with recent Commission precedent in PJM. In September 2018, the Commission found that Order No. 890 did not require incumbent TOs in PJM to transfer their local planning process over to PJM. Instead, the Commission found that incumbent TOs retain primary authority over planning local or Supplemental Projects. Specifically, the Commission explained that "[w]hen transmission owners participate in an RTO, the Commission did not require them to allow the RTO to do all planning for local or Supplemental Projects... The PJM Transmission Owners therefore may retain primary authority for planning local Supplemental Projects…"[93] The Commission would have to revisit this finding to adopt the recommendation to conduct more local transmission planning through the ISO/RTO-coordinated regional planning process, yet the Brattle Report presents no compelling evidence to do so.

5.3. Reliability Projects

Based on our review, we found that the Commission carefully weighed reliability concerns in the Order No. 1000 proceeding. For example, the Commission explicitly recognized an incumbent TO's need to maintain reliability within its local area:

"We clarify that our actions today are not intended to diminish the significance of an incumbent transmission provider's reliability needs or service obligations. Currently, an incumbent transmission provider may meet its reliability needs or service obligations by building new transmission facilities that are located solely within its retail distribution service territory or footprint."*[94]*

In Order No. 1000 compliance proceedings, the Commission recognized that there may be insufficient time to carry out a solicitation if a project is needed to maintain reliability. For example, the Commission approved,

expand the grid, they do not fall within the scope of Order No. 890." *CPUC et al v. PG&E,* Order Denying Complaint, 164 FERC ¶ 61,161 (August 31, 2018), P 66.

92 The Commission found that only grid expansion projects are subject to Order No. 890 reforms. *Id.*

93 *Monongahela Power Company et al*. 164 FERC ¶ 61,217 (September 26, 2018) at P 13.

94 Order No. 1000 at P 262.

with modifications, PJM's proposal to forego solicitations for certain reliability projects that needed to be in service by a certain date to address reliability concerns: "We agree with PJM that there may be instances in which it may not be feasible to hold a competitive solicitation process to solve a reliability violation. Thus, to avoid delays in the development of transmission facilities needed to resolve a time-sensitive reliability criteria violation, we find that it is just and reasonable to include a class of transmission projects that are exempt from the competitive solicitation."[95] The Commission approved similar tariff provisions in ISO-NE and SPP.[96]

We believe the experience with the solicitations that have been held to date have proven the Commission correct. For example, Table 12 in Section 4 shows the timelines of the solicitations with more than one bidder ranged from a low of 133 days to a high of 1,498 days. Given the amount in of time involved, conducting solicitations for transmission projects needed to address a reliability issue may conflict with Commission's recent interest in enhancing the reliability and resilience of the transmission grid.

5.4. State Granted Rights-of-First Refusal

Finally, as explained further in Appendix E, the Commission clarified in Order No. 1000-A that the requirement to eliminate a federal ROFR in certain circumstances does not affect or preempt state laws regarding ROFRs that state or local governments might grant to incumbent TOs because the Order No. 1000 requirements were "focused on Commission-jurisdictional tariffs and agreements, and are not intended to preempt state or local laws or regulations."[97] Accordingly, as the Brattle Report notes,[98] expanding solicitations, especially by a significant degree, would also require changing state or local laws.

95 *PJM Interconnection, L.L.C.*, et al., Order on Compliance Filings, 142 FERC ¶ 61,214 (Mar. 22, 2013) at P 247.
96 See *ISO New England Inc.*, Order on Compliance Filings, 143 FERC 61,150 (May 17, 2013) at PP 235-236 and *Southwest Power Pool, Inc.*, Order on Compliance Filings, 144 FERC ¶ 61,059 (July 18, 2013) at PP 195-199.
97 Order No. 1000-A, at P 379.
98 Brattle Report, p. 21.

6. CONCLUSION

Based on Concentric's review, the results of the Brattle Report are inaccurate and as such, provide no basis to expand the scope of competitive solicitations in FERC-jurisdictional ISOs/RTOs. First, Concentric found that incumbent TOs do not experience the cost overruns claimed in the report. To the contrary, publicly available data from ISOs/RTOs with cost tracking databases suggests that incumbent TOs experience insignificant to very modest changes, ranging from -2.9% to 7.0%, between initial cost estimates and final or updated project cost estimates.

Second, it is not possible to estimate potential savings from the solicitations because the final costs are not known and the cost caps in some of the winning bids are not guaranteed to contain costs. Furthermore, Brattle's savings estimate for the solicitations are inaccurate because Brattle uses an inappropriate benchmark to estimate lower bound savings from the solicitations. The upper bound estimates are also methodologically flawed and rely on over-stated "cost overrun" estimates for incumbent TOs.

Third, expanding the scope of transmission projects selected through competitive solicitations could be inconsistent with the reliability and resilience goals the Commission expressed in recent orders and would require the Commission to directly contradict recent precedent regarding the applicability of Order No. 890. Expanding the scope of solicitations for new transmission projects would also require the Commission to revisit several of its findings in Order No. 1000 as well as more recent orders.

The Brattle Report does not present any credible evidence to suggest that the scope of solicitations for transmission projects should be expanded. However, if there is interest in expanding solicitations for transmission projects, we advise policymakers to wait until more of the projects selected through such solicitations have been placed in service. At such a time, more information will be available about the actual costs and operational performance of these projects and policymakers would be in a position to make better informed decisions about whether or not to expand such solicitations.

APPENDIX A: REVIEW OF INCUMBENT TO COST ESTIMATES

This appendix describes Concentric's analysis of the extent to which incumbent TOs' initial transmission project cost estimates compared to final or updated cost estimates. Concentric conducted this analysis to assess the accuracy of Brattle's estimates of the same figures. A discussion of the data and methods Concentric used to assess the Brattle estimates and produce its own estimates are described below for ISO-NE, MISO, PJM, SPP, and CAISO. Given the limited information about initial cost estimates for incumbent TO projects in NYISO, Concentric did not attempt to produce estimates for NYISO (consistent with Brattle).

ISO-NE

As noted above, the Brattle Report relied on the ISO-NE RSP cost tracking database for three of the 14 incumbent TO projects the report based its 70% cost escalation estimate on (Scobie-Tewksbury, Wakefield-Woburn, and Mystic Woburn).[99] Concentric was able to validate these estimates for the 3 projects that relied on the RSP database, but was unable to validate the Brattle Report's cost escalation estimates for the remaining 11 projects. As noted above, we believe the report inappropriately compared final project costs to early planning-level estimates that were developed before the scope of each project had been defined. For the 11 remaining ISO-NE projects, the Brattle Report relied on a February 2015 NextEra presentation for initial and final project cost figures.[100] Concentric analyzed the siting board decisions to determine the incumbent TO's initial project cost estimates and a February 2015 Eversource and National Grid presentation that responded to the NextEra presentation.[101] For example, the final siting approval order for National Grid's Worcester Reliability project included a range of cost estimates that varied depending on the project route and whether the new transmission lines would be overhead or underground. The lowest cost estimate National Grid provided for the Worcester project was $33.53 million based on a single overhead line and the highest estimate was $70+ million based on two underground lines.[102] In an effort to be conservative and permit the greatest "cost escalation", Concentric's analysis in Table 2 used the lowest cost estimate ($34 million) for the Worcester Reliability project. As shown in Table 2, Brattle used a $7 million initial cost estimate for the Worcester project which resulted in Brattle estimating a 377% escalation – 355% if adjusted for inflation – for this project, compared to Concentric's estimate of 2%. Using the same approach for the Greater Springfield project, the estimated project cost in the September 2010 siting approval for this project was $714.2 million,[103] but the

---

99 Specifically, the Scobie-Tewksbury, Wakefield-Woburn, and Mystic Woburn projects, which the Brattle Report obtained initial and updated cost estimate data from the March 2018 RSP tracking database. See Brattle Report, Figure 25, p. 57.

100 NextEra Energy Transmission, *Greater Boston Cost Comparison*, January, 2015, *available at* https://www.iso-ne.com/static-assets/documents/2015/02/a2_nht_greater_boston_cost_analysis_public.pdf. *See also* Brattle Report, Figure 25, p. 57.

101 National Grid and Eversource, Response to NHT Cost Claims on Selected Projects. February 2015, available at https://www.iso-ne.com/static-assets/documents/2015/02/a2_ngrid_eversource_response_to_nht_greater_boston_cost_claims.pdf.

102 Worcester Reliability project siting board approval, Commonwealth of Massachusetts Energy Facilities Siting Board, Final Decision, Docket Nos. EFSB 09-1, D.P.U. 09-52, and D.P.U. 09-53 (March 11, 2011), Table 2, p. 18.

103 Greater Springfield siting board approval, Commonwealth of Massachusetts Energy Facilities, Final Decision, Docket Nos. EFSB 08-2, D.P.U. 08-105, and D.P.U. 08-106 (September 28, 2010), p. 82.

Brattle Report assumed a $350 million initial cost estimate.[104] The inflation-adjusted installed cost of the Greater Springfield was $676 million. Given the different initial estimates for the Greater Springfield project, the Brattle Report estimates a 117% escalation and Concentric estimates a -5% escalation. Table 14 below compares the Concentric and Brattle estimates of the cost escalations of the 11 projects.

Table 14: Analysis of Brattle Report Estimate of ISO-NE Project Cost Escalations

	Brattle Initial TO Cost Estimate ($ million)	Concentric Initial TO Cost Estimate ($million)	Installed Cost ($million)	Brattle Cost Escalation Estimate	Concentric Cost Escalation Estimate
Stoughton Cable	$213	$213	$317	49%	49%
Southwest Connecticut	$690	$993	$1,274	105%	28%
Norwalk Reliability	$128	$128	$234	83%	83%
Worcester Reliability	$7	$34	$34	377%	2%
Lower SEMA	$107	$107	$105	-2%	-2%
Millstone DCT Elimination	$22	$27	$39	76%	42%
NEEWS – Greater Springfield	$350	$714	$676	117%	-5%
NEEWS – Rhode Island Reliability	$150	$264	$330	110%	25%
Merrimack Valley/North Shore Salem Cables	$43	$62	$63	45%	1%
NEEWS – Interstate Reliability	$400	$542	$542	35%	0%
Stamford Reliability	$49	$47	$37	-15%	-21%

Source: Brattle Estimates: Brattle Report, Figure 25, p. 57. Concentric Estimates: See research above in Appendix A.

MISO

Brattle estimates that the costs of MISO's incumbent TO projects have increased by 18% for the 2015-2018 planning cycles. Because Concentric could not replicate the figures shown in Brattle's Figure 21, we are unable to review Brattle's methodology. However, Concentric reviewed the same publicly available transmission project cost data relied upon by Brattle, which shows that cost escalations ranged from 0.5% to 7.3%, far lower than the Brattle Report estimate.

104 Brattle Report, Figure 25, p. 57.

Table 15: MISO Project Cost Change Estimates

	Initial ($million)		In-Service ($million)		% Change
MTEP 2014	$	9,085	$	9,747	7.3%
MTEP 2015		7,292		7,615	4.4%
MTEP 2016		6,304		6,675	5.9%
MTEP 2017		478		480	0.5%
Total	**$**	**23,159**	**$**	**24,517**	**5.9%**

Concentric reviewed the change between initial estimates and in-service costs for projects approved in the 2014-2017 MISO Transmission Expansion Plans ("MTEP"). Concentric examined the MTEP Appendix AB Projects List from each of the 2014, 2015, 2016, and 2017 MTEP planning cycles.[105] Concentric understands these tracking files represent projects that have been approved by MISO in a given planning cycle. The MTEP quarterly tracking reports, in contrast, represent updates to *some* project cost estimates, if they are known. The quarterly tracking reports therefore do not necessarily provide a complete cost status in any given quarter.

Concentric used MISO's "MTEP In Service Projects" list[106] for final cost estimates. This In-Service Projects list was updated by MISO as of April 29, 2019 at the time of Concentric's analysis. Concentric then compared the total project dollars approved in each of the MTEP 2014-2017 planning cycles to those projects' final in-service costs, to the extent they had been placed in service and reported to MISO as of 4/29/2019. Concentric excluded any projects for which there was no cost estimate, or a zero-dollar cost estimate, for either the initial or the final project costs. This analysis includes projects that had estimates provided in multiple MTEP Appendix AB tracking reports. As shown in Table 15, these projects have experienced a 6% cost escalation.

Finally, Concentric notes that the MISO data can be more difficult to track than other ISO/RTOs. For example, Concentric notes an Entergy Lake Charles Transmission Project had a project cost of $28 million as listed in the 2015 MTEP quarterly tracking reports, but is listed in the 2018 MTEP quarterly tracking reports with a project cost of $181 million for a perceived cost escalation of nearly 550%. Upon closer review, the approval for Entergy's Certificate of Public Convenience and Necessity ("CPCN") notes that the Company's actual initial cost estimate was $187 million.[107] In addition, it is apparent that project cost estimates in the MTEP Appendices are not listed in consistent dollar year terms, nor are they reported with consistent levels of estimation confidence (i.e., some projects list planning level estimates while others list engineering level estimates).

105 Concentric examined total projects, as opposed to individual facilities, of which there can be many under a given project's heading. Projects placed in-service indicate that all facilities are in service for the listed project.

106 https://www.misoenergy.org/planning/planning-test/mtep-quarterly-status-reports/#t=10&p=0&s=&sd=

107 Louisiana Public Service Commission, Order No. U-33645, December 16, 2015, p. 3.

PJM

The Brattle Report claims that Supplemental Projects in PJM are not tracked by the PJM Transmission Construction Status Database.[108] However, Supplemental Projects are tracked in the PJM Transmission Cost Allocation Database, which contains both initial and "latest cost estimates" for these projects.[109] The Concentric estimates thus include project cost tracking data for Supplemental Projects as well.

SPP

Brattle estimates that the costs of SPP's incumbent TO projects developed from 2009 through 2019 experienced cost escalations of 18%. Concentric determined that this estimate is significantly overstated. Table 16 shows the Brattle Report's cost escalation estimates for Balanced Portfolio Projects, Priority Projects, and ITP Portfolio Projects in SPP. In total, the Brattle Report claims that costs have increased from $2,028 million to $2,391 million (without controlling for inflation), for a total cost escalation of 18%. However, upon closer review of each category of projects using the same data sources, Concentric has determined an overall cost escalation of -2%.

Table 16: SPP Incumbent TO Project Cost Estimates

SPP Portfolio	Brattle Initial TO Cost Estimate ($ million)	CEA Initial TO Cost Estimate ($ million)	Latest Cost Estimate ($ million)	Brattle Estimated Cost Escalation	CEA Estimated Cost Escalation	# of Projects
Balanced Portfolio	$691	$832	$831	20%	0%	
Priority Projects	$1,145	$1,416	$1,349	18%	-5%	
ITP Portfolio Projects with Final Cost Estimates (2012 to 2017)	$192		$211	10%		42
ITP Portfolio Projects Listed as Complete (2012 to 2017)		$1,349	$1,330		-1%	150
Brattle Total Comparison	$2,028		$2,391	18%		
Concentric Total Comparison		$3,597	$3,510		-2%	

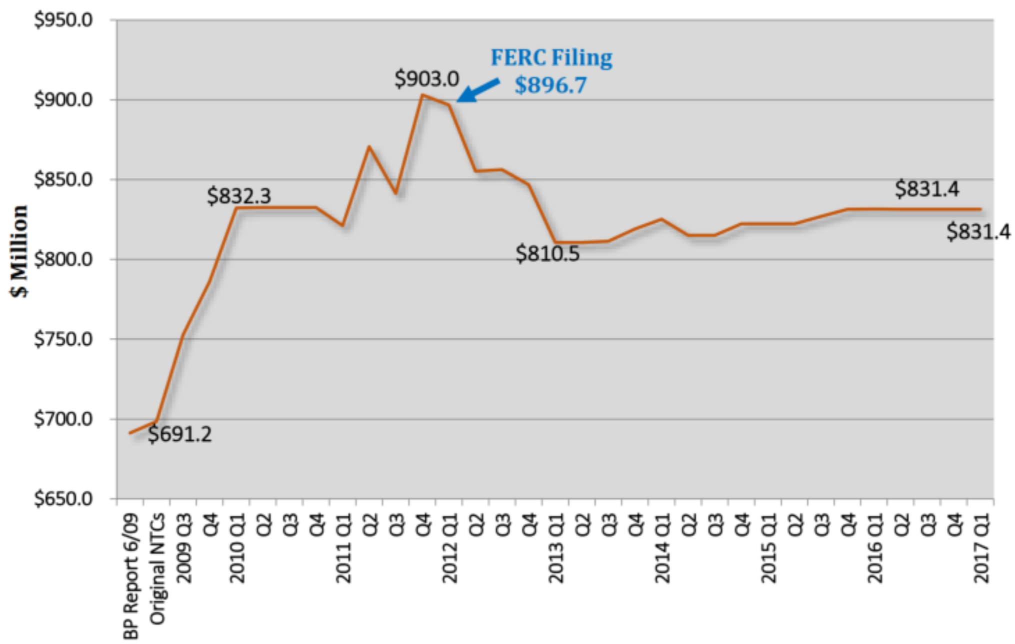
108 Brattle Report, p. 56. See notes in Figure 24.

109 *See e.g.*, https://www.pjm.com/planning/rtep-upgrades-status/cost-allocation-view.aspx

Balanced Portfolio Projects

Brattle relied on the 2017 Q2 SPP Quarterly Tracking Report to estimate the historical cost escalations of Balanced Portfolio Projects. These projects were part of an SPP initiative "to develop a group of economic transmission upgrades that benefit the entire SPP region and allocate those project costs regionally."[110] The figure below reports how estimates of the cost of this portfolio of projects have evolved over the 2009-2017 period.

Figure 4: SPP Balanced Portfolio Cost Estimate Trend



Source: SPP 2017 Q2 Quarterly Project Tracking Report, p. 12

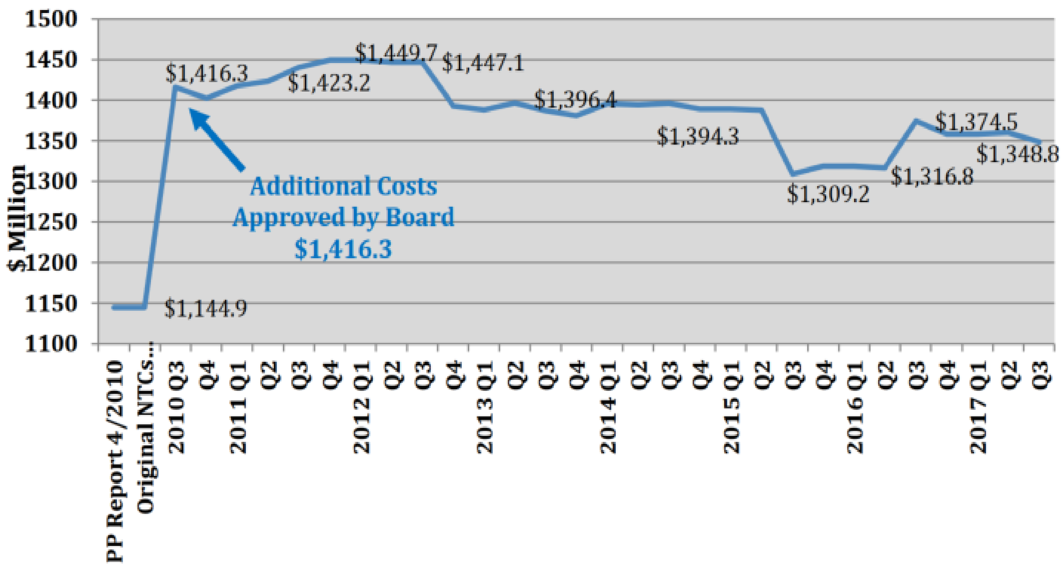
As shown in Figure 4, within 6 months of the original estimate, the cost estimate for the portfolio of Balanced Portfolio projects was revised upward by nearly $150 million. This increase was due to changes that SPP directed to promote a more consistent extra high voltage planning design.[111] This is an example of how estimates change significantly if the scope changes. Concentric believes the cost estimate from 2010 Q1 is a more accurate starting point from which to measure cost increases or decreases because the projects were re-scoped in the intervening months. The result is a 0% cost escalation figure for Balanced Portfolio Projects.

110 SPP 2017 Q2 Quarterly Project Tracking Report, p. 12.
111 SPP 2010 Q1 Quarterly Project Tracking Report, p. 2.

Priority Projects

Brattle relies on the 2017-Q4 SPP Quarterly Tracking Report to represent the cost escalations of Priority Projects. These projects were approved as "priority" high voltage electric transmission projects with large estimated regional benefits. As seen in Figure 5, within six months of the original cost estimates, SPP approved additional costs "due to line rerouting and addition costs for reactive compensation."[112] These types of adjustments could occur with any transmission project, regardless of its developer or the process by which it is selected. The total cost estimate for the SPP Priority Projects after the variances were approved was $1.42 billion.

Figure 5: SPP Priority Project Cost Estimate Trend



SPP 2017 Q4 Quarterly Project Tracking Report, p. 12.

Given the scope changes directed by SPP, Concentric believes the second reported data point is a more accurate starting point from which to measure cost increase or decreases. This results in a -5% cost escalation for Priority Projects.

ITP Portfolio Projects

Brattle relies on the 2019 Q1 SPP Quarterly Tracking Report, Appendix 1 data to represent the cost escalations of ITP Portfolio Projects. Concentric examined the 2019 Q1 tracking data and determined that Brattle did not consider the full sample of completed projects. This means Brattle has filtered the tracking data and only considered 42 projects, excluding over 100 completed projects. In our view, including the larger sample of projects is reasonable as the ultimate project costs are largely known. Including these projects also expands

112 SPP 2017 Q4 Quarterly Project Tracking Report, p. 12.

the project sample size from 42 to 150, which is more broadly representative of the portfolio of projects completed in SPP during the timeframe Brattle considered (2012-2017) and increases the total value of the transmission projects in the sample from $192 to $1,349 million. The change in costs between the initial estimate to the latest cost estimate tracked by SPP is -1%.

In summary, Concentric has examined each of the SPP documents the Brattle Report referenced to better understand these claims. Upon review, Concentric can determine that the Brattle Report's SPP estimates are significantly overstated, and do not necessarily provide the full context of how transmission project costs have evolved in SPP.

CAISO

Figure 23 of the Brattle Report presents estimates of the "historical cost escalation" of incumbent TO projects in CAISO. Figure 23 examines 18 transmission projects and notes that the projects are "not the complete universe of CAISO projects".[113] Figure 23 states that in aggregate, final costs of 18 projects exceeded initial estimates by 33%. However, Figure 23 also states that CAISO only published initial cost estimates for 10 of these projects (the other initial cost estimate data for the other projects was provided to the California Public Utilities Commission). The Brattle Report only used the 10 projects that also had CAISO estimates to calculate CAISO incumbent TO historical cost escalation, which the report estimated was 41%.[114] Limiting this already small sample of projects from 18 to 10 increased the estimated historical cost escalation in CAISO from 33% to 41%.

Concentric reviewed the same sources the Brattle Report cited in Figure 23 to assess the CAISO estimate and determined that the 41% cost escalation estimate is highly sensitive to the sample of projects selected. However, as noted above, we caution that this sample of projects is too small and unrepresentative to constitute a reasonable estimate of how final and/or updated project costs compare to initial incumbent TO estimates in CAISO. Nevertheless, we conducted our analysis to assess the reasonableness and accuracy of the Brattle Report's CAISO estimate.

1. PG&E

Concentric reviewed information about PG&E's initial and final project costs that was available in the FERC dockets referenced in the Brattle Report. Rather than limit the analysis to a subset of projects with initial and final cost estimates, Concentric analyzed all of the PG&E projects that had initial and final project cost information that was available in the FERC dockets referenced in Figure 23 of the report (Docket Nos. ER16-2320-000 and EL17-45-000). Concentric expanded the PG&E sample in two ways. First, the Brattle Report only relies on seven of the eight PG&E projects referenced in FERC Docket No. ER16-2320 while the Concentric

113 Brattle Report, Figure 23, p. 55.
114 Brattle Report, Figure 23, p. 55, at column 6.

analysis included all eight projects.[115] Second, Concentric included initial and final project cost information for 47 additional PG&E transmission projects (Substation and Line Capacity projects) that PG&E provided in response to a California Public Utilities Commission ("CPUC") data request.[116]

As shown in Table 17 below, expanding the sample results in a PG&E cost escalation estimate ranging from 6.1% to 18.8%. In total, this portfolio of PG&E projects experienced an "average" cost overrun of 12.6%. Concentric uses the initial estimates that PG&E provided to CAISO and not the "CAISO estimate" that the Brattle Report used, as such the figures are comparable to column 5 in Figure 23 of the report.

Table 17: Concentric review of Brattle's Historical Cost Escalation Estimate for PG&E

	CAISO Approved Cost ($)		**Final or Updated Cost ($)**
Docket No. EL17-45-000 projects	Low	High	
-Substation Capacity	358,499	485,899	339,842
-Line Capacity	317,600	373,600	437,246
Total	676,099	859,499	777,088
Docket No. EL16-47-000 projects	858,600	858,600	1,046,408
Total Estimate	1,534,699	1,718,099	1,823,496
Final or Updated - CAISO Approved ($)	288,797	105,397	
Final or Updated - CAISO Approved (%)	18.8%	6.1%	

Docket No. EL16-47-000 Projects: Exhibit CPUC-001, Prepared Direct Testimony of Geneva Looker, Docket No. ER16-23-20-000, p. 24, Table J (filed July 5, 2017). Docket EL17-45-000 Projects: California Parties v. Pacific Gas and Electric Co., (filed Feb. 2, 2017) Docket No EL17-45-000, Exhibit 2 - PG&E Response to CPUC Data Request, pp 4-6.

2. <u>SDG&E</u>

To estimate average historical cost escalations for SDG&E, Brattle Report relied on initial and updated project cost estimates that SDG&E provided to the CPUC. However, rather than use information for all 17 of the projects supplied, Brattle excluded seven projects in column 5 of Figure 23, without explanation, and estimated an average cost escalation of 19.7% for SDG&E. Brattle then limited the sample further to 3 projects with a "CAISO estimate" (column 3 of Figure 23), which results in an estimated escalation of 2.3% for the 3 projects. If Brattle had used all 17 projects, the average cost escalation would be 5.9% as demonstrated by Concentric. Although the sample of 17 is still limited and not necessarily representative of SDG&E's overall portfolio of projects, it provides a better estimate than the three SDG&E projects the Brattle Report used to estimate historical cost escalation in CAISO.

115 Exhibit CPUC-001, Prepared Direct Testimony of Geneva Looker, Docket No. ER16-23-20-000, p. 24, Table J (filed July 5, 2017). Table J references Docket No. EL16-47-000, where PG&E sought abandoned plant recovery for certain transmission projects. The Brattle Report sample for PG&E excluded a project that had final costs that were below PG&E's initial estimate.

116 This information was included as an Exhibit to a February 2017 complaint filed at FERC (Docket No. EL17-45-000). *See California Parties v. Pacific Gas and Electric Co.*, (filed Feb. 2, 2017) Docket No EL17-45-000, Exhibit 2 - PG&E Response to CPUC Data Request, pp. 4-6.

It warrants mention that most of SDG&E's final project costs were below the initial cost estimates. One project - the East County ("ECO") Substation project referenced in Figure 23 of the Brattle Report - experienced significant cost overruns due to an unplanned routing change directed by the CPUC. During the permitting process, the CPUC required undergrounding a portion of the line. As a result, the final project cost for the ECO Substation was $410 million, a 50% increase above the initial cost of estimate $273 million.[117] We note this to reiterate that greenfield transmission projects face significant cost risks due to factors beyond the developer's control, such as regulatory siting and permitting issues.

Table 18: Sample of SDG&E Transmission Projects completeed Jan. 2014 – Nov. 2016

	Initial Project Cost Estimate ($)	**Final Project Cost ($)**	**Difference ($)**	**%**
TL 637 CRE-ST SW Pole Replacements	45,000,000	39,570,571	-5,429,429	-12.1%
Mira Sorrento 138/12KV Sub & Cirs. 1442 Thru 1446	50,300,000	18,733,717	-31,566,283	-62.8%
ECO Substation	273,000,000	409,839,624	136,839,624	50.1%
Poseidon Project-Modify Cannon Sub & Install 2 Ckts	14,500,000	11,332,962	-3,167,038	-21.8%
New TL ES-Ash #2	21,600,000	4,661,923	-16,938,077	-78.4%
IV West Generator Interconnection (Q608)	2,114,000	1,114,439	-999,561	-47.3%
TL694A Melrose Loop-In Project	41,363,000	33,788,430	-7,574,570	-18.3%
TL6914 Los Coches-Loveland SW Pole Replace	40,000,000	23,929,019	-16,070,981	-40.2%
Talega-Add Synchronous Condensers	64,400,000	80,840,653	16,440,653	25.5%
Shunt Reactor on Suncrest 500kV Bus	10,900,000	9,834,023	-1,065,977	-9.8%
Sunnyside 69/12kV Rebuild	16446000	9,780,217	-6,665,783	-40.5%
Pio Pico Energy Ctr.	9,422,000	9,584,640	162,640	1.7%
Wabash Substation Rebuild	6,100,000	9,777,332	3,677,332	60.3%
Relocate South Bay Substation	129,200,000	120,732,727	-8,467,273	-6.6%
Talega Bank 50 Replacement	5,500,000	2,138,852	-3,361,148	-61.1%
TL13821 and TL13828-Fanita Junction Enhancement	41,400,000	35,318,965	-6,081,035	-14.7%
Encina Bank 61	11,156,000	7,873,169	-3,282,831	-29.4%
Full sample (17 projects)	782,401,000	828,851,263	46,450,263	5.9%
Brattle sample (10 projects)	568,692,000	680,824,576	112,132,576	19.7%

Source: California Parties Complaint, filed Feb. 2, 2019 in Docket No. EL17-45-000, Exhibit 3, page 7.
*SDG&E indicated that this cost estimate was provided at the time the project first appeared on the AB970 report to the CPUC.

117 *See e.g.*, CPUC proceeding for SDG&E CPCN application for the East County Substation (Application A.09-08-003).

3. SCE

The Brattle Report did not use any Southern California Edison (SCE) projects to estimate historical cost escalation of CAISO incumbent TO projects despite the fact that SCE is the second largest incumbent in CAISO. However, Figure 23 of the Brattle Report references a single project – the Tehachapi project that was completed in 2014. The Tehachapi project constitutes another example of the fact that transmission projects, particularly projects that require a new CPCN, face risks that are beyond the developer's control.[118] The Tehachapi project was a complex greenfield project and, as a result, faced significant and unexpected citing issues that other projects (e.g., upgrades don't typically require a CPCN) are unlikely to face. As such, the cost escalation experienced in the Tehachapi is not representative of the risk that the full portfolio of SCE projects will face.

The Tehachapi project was a large greenfield project designed to interconnect approximately 4,500 MW of generation capacity to the SCE system. Construction was split into 11 segments. SCE's preliminary cost estimate for segments 4-11 of the Tehachapi project was $1.72 billion (in 2009 dollars).[119] In December 2009, the CPUC issued a CPCN for these segments, which included an overhead route in the City of Chino Hills, California area (segment 8A). However, parties in the Chino Hills areas sought rehearing of this decision regarding segment 8A and in January 2010, 22 months after issuing the initial CPCN, the CPUC issued a stay on the construction of segment 8A, and SCE ceased construction activities on that segment, despite the fact that segment 8A was almost completed in an overhead configuration. In July 2013, the CPUC reversed its initial December 2009 decision of the CPCN for segment 8A and directed SCE to construct about 3.5 miles of segment 8A in the Chino Hills area underground. SCE also had to remove newly constructed overhead transmission structures and substation facilities it had constructed in accordance with the initial 2009 CPCN for the segment.[120] In 2014, FERC granted SCE's request to recover $14.445 million in abandoned plant to recover the costs of project support, engineering, environmental monitoring, and mitigation activities; direct material and construction costs; removal activity; and certain overheads associated with these expenditures.[121]

---

118 See e.g., *Southern California Edison Company*, Order on Abandonment Cost Recovery Filing, 148 FERC ¶ 61,126 at PP 2-7 (Aug. 15, 2014).

119 Southern California Edison, Certificate of Public Convenience and Necessity Concerning the Tehachapi Renewable Transmission Project (Segments 4 through 11), Opening Brief, Application No. 07-06-031 (June 28, 2007), at *ix*. This estimate excludes Allowance for Funds Used During Construction.

120 *Southern California Edison Company*, Order on Abandonment Cost Recovery Filing, 148 FERC ¶ 61,126 at PP 2-7 (Aug. 15, 2014).

121 *Southern California Edison Company*, Order on Abandonment Cost Recovery Filing, 148 FERC ¶ 61,126 at P 10. (Aug. 15, 2014). Specifically, the $14.445 figure includes This amount includes: (1) $11.667 million in direct expenditures for construction of the overhead structures and substation, facilities that are now abandoned; (2) $3.595 million in costs for the removal of the overhead facilities; and (3) $38,000 in additional expected removal costs. SCE reduced its overall expenditures by $645,000 for reusable structures and by $210,000 for salvageable items.

APPENDIX B: ESTIMATING TRANSMISSION PROJECT COSTS

Estimating the cost of transmission projects is an inherently difficult task, as is the case with any large capital project. Most large transmission projects face risks to schedules and budgets at every step—from feasibility, siting, permitting and design to construction and operation. While there are many factors that can impact schedule and budget, they generally fall into three categories: i) economic and commercial risks; ii) regulatory issues; and iii) public opposition. Together, all of these elements have the potential to significantly impact project costs by altering project scope, prolonging project timelines and adding uncertainty to already complex financing processes, contributing to cost variances from the preliminary budget estimate.

Economic and commercial considerations are a fundamental part of the justification or rationale for planning and constructing a transmission project. Transmission planning often involves a host of economic assumptions and supporting analytic activities to demonstrate that a project is warranted. All economic and commercial considerations and associated cost forecasts are anchored to the time when they are made. As time passes, the assumptions upon which these considerations rest can change. For example, the price of steel may fall (or rise) between the time a project is conceived and the time it is built. In some instances, for example if the project is not needed for reliability, these changes may be so large that they undermine the economic or commercial viability of the project, and the project may be cancelled. The long lead times associated with development of transmission projects increases their exposure to these factors.

In addition, regulatory risks can threaten project budgets and schedules. States generally hold authority to issue a CPCN for construction and operation of a transmission line; this authority is most frequently under the jurisdiction of a state public utility commission. A CPCN is typically required for a transmission developer to construct facilities to transport electricity at transmission (and sometimes lower, sub-transmission) voltages within a state's borders. Issuance of a CPCN is based on a finding by the state authority that the proposed project is in the public interest. The public interest standard is typically measured by assessing the cost incurred by ratepayers against the expected economic impacts of a project within the state. For projects that involve more than one state, differences among the involved states' CPCN policies and processes must also be addressed. The risk of protracted regulatory processes to assess the public benefit of proposed transmission construction can threaten both cost and schedule estimates.

Finally, public opposition can play a significant role in a developer's ability to meet project cost thresholds and schedule milestones. Organized public opposition to proposed transmission lines has frequently had a material impact on project development by adding time to siting and routing processes, and it has sometimes led or contributed to the cancellation of projects or to the addition of mitigation measures that have increased the project developers' costs. For example, as described in Section 2, many of the projects Brattle used to estimate cost escalations in ISO-NE experienced such issues. Project developers frequently attempt to reduce these costs and associated time requirements through up-front information sharing and joint (and early) development of mitigation approaches. The success of these activities has hinged largely on the extent to which they lead to meaningful engagement and tangible commitments to address public concerns over line routing. For transmission line projects involving federal lands, compliance with the National Environmental Policy Act ("NEPA") involves a sequence of open processes: scoping meetings, public reviews of both a draft and final EIS, and issuance of a Record of Decision. Because of their geographic scope, multi-state transmission projects can entail coordination among more than one federal agency, multiple state offices, and also related state, tribal, and local agencies during the approval process. Approval processes involving multiple agencies raise many institutional issues that sometimes result in significant mitigation costs and time requirements to obtain final approval for a route involving non-private lands.

A good example of the impact these factors can have on schedule and budget was demonstrated in Texas. The Competitive Renewable Energy Zones ("CREZ") initiative was a multiyear effort to connect wind from West Texas to cities in the eastern part of the state that demanded more power. The new transmission projects cost Texas ratepayers over $6.8 billion, far higher than the $4.9 billion projection in 2008.[122] Inflation drove some of the increase. However, the increased scope of the project was a bigger factor. In calculating the original estimate, early cost estimates assumed the transmission lines would follow the most direct routes. As the process played out, however, regulators minimized intrusion by redrawing the routes to follow fences or roads. Those decisions added more than 600 miles of power lines that weren't originally planned.

In addition to the factors impacting the cost and schedule of transmission build noted above, the process used to develop the cost estimate does not lend itself to accurate cost variation analysis. First, many of the initial cost estimates, on which variances are frequently measured, are based on planning level information. These conceptual estimates often lack detailed engineering or design detail and are typically prepared from historical data and used for screening purposes only. However, as discussed further below, the precision of the ISOs/RTOs initial cost estimates, often measured by a percentage confidence level, varies.

For example, in SPP, once a project passes the conceptual screening criteria, a study estimate is prepared that is a more refined estimate of the cost of the transmission project. This project estimate often establishes the baseline for the project cost variance going forward. According to the SPP cost estimate guidelines, the project development stage has a direct impact on the precision of the cost estimate as shown in Table 1 below.

---

122 *See e.g.*, The Texas Tribune, *$7 Billion Wind Power Project Nears Finish*, October 13, 2013, available at https://www.texastribune.org/2013/10/14/7-billion-crez-project-nears-finish-aiding-wind-po/

Table 19: Southwest Power Pool Cost Estimate Stage Definition

Estimate Name	Level of Project Scope Definition	Precision Bandwidth
Conceptual	0% - 10%	-50% to +100%
Study	10% - 20%	-30% to +30%
Conditional Notification to Construct or Notification to Construct	20% - 40%	-20% to +20%
Design and Construction	40% - 100%	-20% to +20%

Source: SPP Cost Estimates Presentation, Katherine Prewitt, May 2011.

The precision of the cost estimate increases as the project progresses from the concept and study phase to the design and construction phase. The project's cost estimates become more precise as the developer acquires more information about the specifications of the project and updates the estimates accordingly. For example, equipment cost estimates become more precise after the developer learns more about the specific technical needs of new equipment. It is common practice to obtain multiple quotes for various project components. For a greenfield transmission project, better information on the route allows a developer to get a better sense of the construction costs and the equipment required to construct the project.

MISO uses different definitions for the various estimates it instructs developers to produce for cost tracking purposes. Table 20 shows that the precision of project estimates increase over time as more information becomes available, shown in the table as an increase in the "maturity level of project definition deliverables".

Table 20: MISO Cost Estimate Stage Definition

	Primary Characteristic	*Secondary Characteristic*		
ESTIMATE CLASS	**MATURITY LEVEL OF PROJECT DEFINITION DELIVERABLES** Expressed as % of complete definition	**END USAGE** Typical purpose of estimate	**METHODOLOGY** Typical estimating method	**EXPECTED ACCURACY RANGE** Typical variation in low and high ranges [a]
Class 5	0% to 2%	Concept screening	Capacity factored, parametric models, judgment, or analogy	L: -20% to -50% H: +30% to +100%
Class 4	1% to 15%	Study or feasibility	Equipment factored or parametric models	L: -15% to -30% H: +20% to +50%
Class 3	10% to 40%	Budget authorization or control	Semi-detailed unit costs with assembly level line items	L: -10% to -20% H: +10% to +30%
Class 2	30% to 75%	Control or bid/tender	Detailed unit cost with forced detailed take-off	L: -5% to -15% H: +5% to +20%
Class 1	65% to 100%	Check estimate or bid/tender	Detailed unit cost with detailed take-off	L: -3% to -10% H: +3% to +15%

Notes: [a] The state of process technology, availability of applicable reference cost data, and many other risks affect the range markedly. The +/- value represents typical percentage variation of actual costs from the cost estimate after application of contingency (typically at a 50% level of confidence) for given scope.

Source: MISO, Transmission Cost Estimation Guide – MTEP19, March 9, 2019, p. 4. Note: MISO described the different types of project cost estimates as follows: Class 3: MISO scoping cost estimate; and Class 4: MISO planning-cost estimate; Class 5: MISO exploratory cost estimate.

It is important to note that the category of estimates shown in the table above do not include any contingency amounts. Contingency is added to a project estimate to allow for uncertain or unexpected events which will likely result in additional costs. Contingency for transmission projects can range from approximately 5% to 50% of total construction costs, and contingency amounts tend to be highest during the early stages of a project's development process. In addition to the improper comparison of different types of cost estimates, e.g., use of a baseline cost estimate, other factors can lead to perceived cost variances that are only due to inflation, a cost escalating factor that the Brattle Report also notes.

APPENDIX C: ORDER NO. 1000 SOLICITATION DETAILS

This appendix describes the transmission solicitations reviewed in the report in more detail. As of the writing of this report, solicitations have been carried out through the ISO/RTO regional transmission planning processes in CAISO, MISO, NYISO, PJM, NYISO, and SPP, and these solicitations are discussed in turn in the remainder of this appendix.

CAISO

As of the writing of this report, the California ISO (CAISO) has had ten solicitations, but the last solicitation occurred in 2015. After CAISO selects a winning proposal from a solicitation, it executes an Approved Project Sponsor Agreement ("APSA") that specifies, among other things, the project's capital cost, operating and maintenance, and other terms the project developer included in its proposal that affect the annual transmission revenue requirement associated with the project. Below is a summary table of Concentric's research to recreate the figures in the Brattle table that purportedly summarized the cost savings associated with competitive transmission solicitations in CAISO. Concentric was only able to locate the APSAs of seven of the CAISO solicitations. Specifically, Concentric was not able to locate the costs of the bids of three projects of CAISO investor-owned utilities PG&E and SDG&E.

Concentric determined that the "cost savings" estimates for CAISO in figure 18 of the Brattle Report compare a CAISO planning-level estimate with the winning bid. The table below summarizes Concentric's recreation of the CAISO figure in Figure 12 of the Brattle Report. If the CAISO planning estimate was a range, Brattle used the high end of the range to calculate the savings in Figure 18, which maximized the estimated savings. Concentric recreated the $1,180 million figure Brattle used as the "RTO/ISO Incumbent estimate of project cost" figure for total planning estimate costs but not the $833 million figure given we could not identify APSAs for the Wheeler Ridge, Spring, and Miguel substations

Table 21: Summary of CAISO Transmission Solicitations

Project	Winning Bid	CAISO Planning Estimate ($ million)	Project Cost in Approved Sponsor Agreement ($)	Winning Bid vs. High CAISO Planning Estimate (low-high%)
Gates-Gregg (delayed)	PG&E /MidAmerican	115 – 145	157,021,766	-8 – 37%
Imperial Valley Element	Imperial Irr. Dist.	25	14,283,122	-43%
Sycamore – Penasquitos	SDG&E	111 – 221	129,975,759	-41% –17%
Delaney to Colorado River	DCR Transmission	-300	241,805,391	-19%
Estrella	NextEra	35 – 45	24,539,000	-30 – -45%
Wheeler Ridge	PG&E	90 – 140	Unknown	
Suncrest	Next Era	50 – 75	42,288,000	-44% – -15%
Spring Sbstn. Morgan Hill	PG&E	35 – 45	Unknown	
Harry Allen to Eldorado	DessertLink	144,000,000	147,000,000	2%
Miguel	SDG&E	30 – 40	Unknown	
Total	Range	$935-1,820		
	Average	$1,058		
Brattle figure for winning bids			$833,000,000	
Total winning bids w\out Wheeler, Spring, and Miguel			$756,913,038	
Avg. "savings" w\out Wheeler, Spring, and Miguel			3-26%	

Suncrest

Project Type: Policy[123]

Project detail: 300 MVAr dynamic reactive power support element connecting to the Suncrest 230 kV bus. SVC or synchronous condenser

Bid window: April 16, 2014 - June 16, 2014[124]

Bidders:

- NextEra Energy Transmission West, LLC ("NEET West")
- San Diego Gas and Electric Company

Winner: NEET West, who offered a project construction cost cap of $42,288,000 in 2015 dollars, with operation and maintenance costs for the first five years of operation capped at $360,000 per year. NEET West signed an APSA with CAISO on May 7, 2015.[125]

123 CAISO, Key Selection Factors in Selection of Successful Project Sponsors Relating to the 2013-2014 Transmission Plan, May 1, 2014, p. 2.

124 CASIO, Suncrest Valley List of Validated Project Sponsor Applications with Sufficient Information, August 5, 2015, p. 1.

125 NEET West Certificate of Public Convenience and Necessity for the Suncrest Dynamic Reactive Power Support Project, Application A.15-08-027, Exhibit NEET West-10, filed August 31, 2015, Approved Project Sponsor Agreement-Appendix E, p. 43.

ISO Implementation Cost: $260,572[126]

ISO Project Cost Estimate: $50 - 75 million, produced April 2014.[127]

Delaney to Colorado River

Project detail: New 500 kV transmission line and associated series compensation between Delaney Substation and Colorado River Substation. Only the 500 kV transmission line and series compensation were eligible for solicitation. The facilities necessary at Delaney Substation and Colorado River Substation to interconnect with the project, including anticipated shunt reactors, were not eligible for solicitation per the CAISO tariff.[128]

Bid window: August 19, 2014-November 19, 2014[129]

Bidders:[130]

- DCR Transmission, LLC (A joint venture between Abengoa Transmission & Infrastructure and an affiliate of Starwood Energy Group Global, Inc.)
- California Transmission Development LLC (a wholly owned subsidiary of LS Power & Associates)
- Duke-American Transmission Company LLC, in collaboration with Western Area Power Administration Desert Southwest Region, and Citizens Energy Corporation.
- NextEra Energy Transmission West LLC (a wholly owned subsidiary of NextEra Energy Transmission)
- TransCanyon DCR LLC in collaboration with Southern California Edison

Winner: DCR Transmission, LLC. According to CPCN filed with CPUC for the "Ten West", the APSA had a cost cap of $ 241,805,391 and was signed December 1, 2015.[131] Updated project cost estimates were $279,560,483 in 2020, provided in October 2016.[132]

ISO Project Cost Estimate: $300 million in 2014 dollars, produced July 2014[133]

*Expected In-Service Date***:** May 1, 2020

ISO Implementation Cost: $530,359[134]

Estrella Project

Need: reliability

126 CAISO, Summary of Accrued Project Sponsor Costs – Suncrest, March 20, 2015, p. 1.
127 CAISO, Suncrest 230 kV 300 MVAr Dynamic Reactive Power Support Description and Functional Specifications for Competitive Solicitation, April 15, 2014, p. 2.
128 CAISO, Delaney to Colorado River Project Sponsor Selection Report, July 10, 2015, at 2.
129 CAISO, Delaney to Colorado River Project Sponsor Selection Report, July 10, 2015, at 2 p. 2.
130 CAISO, Delaney to Colorado River Project Sponsor Selection Report, July 10, 2015, at 3.
131 DCR Transmission, Application for a Certificate of Public Convenience and Necessity for Ten West Link Project, Application A.1610-012, Appendix N, Approved Project Sponsor Agreement, October 12, 2016, p. 45.
132 DCR Transmission, Application for a Certificate of Public Convenience and Necessity for Ten West Link Project, Application A.1610-012, October 12, 2016, p. 12.
133 CAISO, Delaney to Colorado River 500 kV Transmission Line Project Description, Key Selection Factors, and Functional Specifications for Competitive Solicitation, July 2014, p. 2.
134 CAISO, Delaney to Colorado River 500 kV Transmission Line, Summary of Accrued Project Sponsor Costs, Updated December 7,

Project detail: new 230/70 kV substation approximately five miles east of the existing Paso Robles substation. Reliability-driven need to reinforce the 70 kV system to increase the reliability and mitigate thermal overloads and voltage concerns in the Templeton and Estrella areas. The Estrella Project includes a 230/70/12 kV substation, Estrella Substation, new 230/70kV and 230/12 kV transformers, and reconductoring and looping the existing transmission lines. Only the 230/70 kV transformer, 230 kV switchyard, and 230 kV termination structures were eligible for solicitation. The 230/12 kV transformer, 70 kV bus work and termination equipment, and modifications to existing facilities were not eligible for solicitation under the CAISO Tariff.[135]

Bid window: April 16, 2014 – August 18, 2014

Bidders:[136]

- Brookfield California Transmission, LLC (Brookfield CalTrans), an affiliate of Brookfield Asset Management, Inc.
- Golden State Transmission, LLC (Golden State), a joint venture company owned by Edison Transmission, LLC and Transource Energy, LLC
- NextEra Energy Transmission West, LLC ("NEET West")
- Pacific Gas and Electric Company (PG&E)

Winner: NEET West, which signed an APSA with a cost cap of $24,539,000 and a binding annual O&M cost cap for the first five years following commencement of commercial operation.[137]

ISO Implementation Cost: $206,104[138]

ISO Project Cost Estimate: both the solicitation portion and incumbent TO portions were estimated to cost between $35-$45 million.[139]

Proposed In-service Date: May 2019

Harry Allen to Eldorado

Need: economics

Project detail: new 500 kV line between SCE's 500 kV Harry Allen Substation and NV Energy's 500 kV Eldorado Substations. Approximately 60 miles in length.[140]

Bid window: January 30, 2015 - April 30, 2015.

Bidders:

---

135 CASIO, Estrella Project Sponsor Selection Report, March 11, 2015, p. 2.
136 CASIO, Estrella Project Sponsor Selection Report, March 11, 2015, p. 3.
137 *NextEra Energy Transmission West, LLC*, Order on Participating Transmission Owner Tariff and Rate Incentives Proposal, and Establishing Hearing and Settlement Judge Procedures, 154 FERC ¶ 61,009 (Jan. 8, 2016) at note 12.
138 CAISO, 2013-2014 Transmission Planning Process - Revised Summary of Accrued Project Sponsor Costs, November 11, 2014, p. 1.
139 CAISO, Estrella Substation Project Description and Functional Specifications for Competitive Solicitation, June 26, 2014, p. 3.
140 CAISO, Harry Allen-Eldorado 500 kV Transmission Line Project Sponsor Selection Report, January 11, 2016, pp. 2, 10.

- DesertLink, LLC ("DesertLink"), a wholly-owned subsidiary of LS Power Associates, L.P.
- Exelon Transmission Company, LLC, a wholly-owned subsidiary of Exelon Corporation
- NextEra Energy Transmission West, LLC, an affiliate of NextEra Energy, Inc., in collaboration with Southern California Edison Company (NEET West/SCE)

Winner: DesertLink

ISO Implementation Cost: $434,703[141]

ISO Project Cost Estimate: $144 million.[142]

Proposed In-Service Date: May 1, 2020

Notes on FERC Rate: According to an October 2017 formula rate filing with FERC (Docket No. ER17-135-000, et al.) DesertLink and CAISO executed an APSA on June 20, 2016. DesertLink agreed in the APSA with CAISO to limit recovery of capital costs to $147 million for the project, subject to certain conditions and exceptions. Pursuant to a settlement FERC certified in May 2018,[143] DesertLink has agreed to limit equity as a percentage of its capital structure to 50% and to limit the return on equity ("ROE") included in its annual transmission revenue requirement ("ATRR") to 9.8% inclusive of a 50 basis point adder for CAISO membership.[144] Desert Link also agreed in the settlement that the transmission line will be in service by May 1, 2020, and that the transmission revenue requirement cost cap used in winning the competitive bid ($147 million) will be adhered to.

Wheeler Ridge Junction

Need: reliability

Project detail: Build a new 230/115 kV transmission substation at Wheeler Ridge Junction as well as CDWR pumps, with a more reinforced 230 kV source from Kern PP. The facilities in the Wheeler Ridge Junction substation project that are eligible for solicitation are the 230 kV bus-work and termination equipment, and the 230/115 kV transformers. The 115 kV bus-work and termination equipment and modifications to existing facilities are not eligible for solicitation. For the interconnection of the existing 230kV lines to the Wheeler Ridge Junction substation, the incumbent PTO (PG&E) was responsible to bring the new transmission line extensions up to a point within 100 feet of the new substation fence.[145]

Bidders:

- Brookfield Transmission

141 CAISO, 2013-2014 Transmission Planning Process, Harry Allen to Eldorado 500 kV Transmission Line Summary of Accrued Project Sponsor Costs.
142 CAISO, Harry Allen-Eldorado Project Description and Functional Specifications, January 7, 2015, p. 1.
143 *Desert Link, LLC*, Certification of Uncontested Settlement, 163 FERC ¶ 63,014 (May 24, 2018).
144 Id. at P 5. See also http://www.cpuc.ca.gov/General.aspx?id=5240
145 CAISO, Wheeler Ridge Junction Substation Project Description and Functional Specifications for Competitive Solicitation, June 16, 2014, pp. 2-3.

- Golden State Transmission
- PG&E
- NextEra Energy Transmission West, LLC

Winner: PG&E

ISO Implementation Cost: $151,179[146]

ISO Project Cost Estimate: $90-140 million, including both the competitive and noncompetitive portions, to be between, produced June 2014[147]

Proposed In-Service Date: May 2020

Miguel
Need: reliability

Project detail: The reactive power support is required to provide continuous reactive power support with one of the following types of devices: SVC (Static VAR Compensator); STATCOM (Static Synchronous Compensator); or Synchronous Condenser. SDG&E will design, engineer, install, own, operate, and maintain the necessary equipment additions within Miguel substation.[148]

Bid window: April 16, 2014 - June 16, 2014

Bidder: San Diego Gas and Electric Company ("SDG&E")

Winner: SDG&E

ISO Evaluation Cost: $15,056[149]

ISO Project Cost Estimate: $30-$40 million[150]

Proposed In-Service Date: June 1, 2017. Project completed.

Spring Substation
Need: reliability

Project detail: Construct a new 230/115 kV substation, Spring Substation, west of the existing Morgan Hill Substation. Install a new 230/115 kV 420 MVA transformer at Spring Substation. Loop the existing Morgan

---

146 CAISO, 2013-2014 Transmission Planning Process - Revised Summary of Accrued Project Sponsor Costs, November 11, 2014, p. 2.
147 CAISO, Wheeler Ridge Junction Substation Project Description and Functional Specifications for Competitive Solicitation, June 16, 2014, p. 3.
148 CAISO, Key Selection Factors in Selection of Successful Project Sponsors Relating to the 2013-2014 Transmission Plan, May 1, 2014, p. 2.
149 CAISO, 2013-2014 Transmission Planning Process, Summary of Accrued Project Sponsor Costs - Miguel, November 11, 2014.
150 CAISO, Miguel 500 kV 375 MVAr Reactive Power Support Description and Functional Specifications for Competitive Solicitation, May 1, 2014, p. 1.

Hill-Llagas 115 kV Line into the Spring 115 kV bus using a portion of the idle Green Valley-Llagas 115 kV Line right-of-way.

Bid window: April 16, 2014 - August 18, 2014

Bidders:

- NextEra Energy Transmission West, LLC
- Brookfield California Transmission West, LLC
- Pacific Gas and Electric Company

Winner: PG&E

ISO Evaluation Cost: $165,912[151]

ISO Project Cost Estimate: $35-45 million, produced June 2014

Proposed In-service Date: May 2021[152]

Sycamore – Penasquitos

Need: policy

Project: 230 kV transmission line between SDG&E owned Sycamore and Penasquitos 230 kV substations.[153]

Bid window: April 1, 2013 - June 3, 2013

Bidders:[154]

- Abengoa T&D
- Elecnor, Inc
- SDG&E
- Trans Bay Cable LLC

Winner: SDG&E

APSA: initial: $129,975,759 (2014). Revised: $ 259,670,632 (2015)

Notes: The CAISO filed the initial APSA between SDG&E and the CAISO with FERC on August 11, 2014 in Docket No. ER14-2629-000. The CPUC issued its final certificate for the project on October 13, 2016, and it required the project to place the majority of the transmission line underground, whereas the CAISO specification assumed that the majority of the line would be placed above ground and in SDG&E's existing rights-of-way.

151 CAISO, 2013-2014 Transmission Planning Process - Revised Summary of Accrued Project Sponsor Costs, November 11, 2014, p. 1.
152 CAISO, Spring Substation Project (Morgan Hill Area) Description and Functional Specifications for Competitive Solicitation, June 26, 2014, p. 3.
153 CAISO, Sycamore-Penasquitos 230 kV Line Description and Functional Specifications Eligible for Competitive Solicitation, April 1, 2013, p. 1.
154 CAISO, Sycamore-Penasquitos Project Sponsor Selection Report, March 4, 2014, p. 4.

However, the CPUC certificate decision requires the SDG&E to underground the majority of the line, which increases the estimated cost to $260 million and extended the energization date to June 30, 2018.[155]

ISO Project Cost Estimate: $111-221 million, produced April 2013[156]

Proposed in-service date: Initial- May 2017, Revised- June 2018

Gates-Gregg
Need: Reliability

Project: The Gates-Gregg Project is a 230 kV transmission line that originates from the PG&E Gates Substation and terminates at the PG&E Gregg Substation. The Gates-Gregg Project includes the transmission line itself, all required work within the fence line of each substation is not included as part of the Gates-Gregg Project.

Window: April 1, 2013 - June 3, 2013.[157]

Bidders:[158]

- Elecnor Inc.
- Isolux Infrastructure
- PG&E and MidAmerican Transmission
- Pattern Energy Group LP and the City of Pittsburg
- G2G ProjectCo LLC (Trans Bay Cable)

Winner: PG&E and MidAmerican Transmission

Approved Sponsor Agreement: $ 157,021,766 (2013 dollars), signed August 31, 2014.

ISO Project Cost Estimate: $115 - $145 million[159]

Proposed In-service: Initially March 31, 2020, but now December 2022 per the CAISO 2017-2018 transmission plan.[160]

Notes: Per a filing on May 17, 2018 in Docket No. ER17-1628, CAISO requested an amendment to the APSA to revise the milestones so that the permitting and construction of the Gates-Gregg Project could be put on hold pending the results of the CAISO 2017-2018 transmission planning process. In reviewing the Gates-Gregg Project in the CAISO's 2016-2017 Transmission Planning Process, due to a decrease in the forecasted load the Gates-Gregg Project may no longer be needed.[161]

155 CAISO Transmittal Letter, Docket No. ER17-1627-000, May 18, 2017, pp. 1-2.
156 CAISO, Sycamore-Penasquitos 230 kV Line Description and Functional Specifications Eligible for Competitive Solicitation, April 1, 2013, p. 2.
157 CAISO Transmittal Letter, Docket No. ER14-2347-000, July 1, 2014.
158 CAISO, Gates Gregg Selection Report, p. 2.
159 CAISO, Gates-Gregg 230 kV Description and Functional Specifications for Competitive Solicitation, April 1, 2013, p. 2.
160 CAISO, 2017-18 Transmission Plan, March 22, 2018, p. 135.
161 CAISO-Gates Greg Approved Sponsor Project Agreement, filed May 18, 2017 in Docket No. ER17-1628.

Imperial Valley
Need: policy

Project detail: 230 kV collector substation (located approximately one mile north of the Imperial Valley ("IV") substation) and a 230 kV transmission line connecting the collector substation to the IV substation.

Bidders:[162]

- Imperial Irrigation District
- Abengoa Transmission & Distribution

Winner: Imperial Irrigation District[163]

Winning bid: $14,283,122

Notes: CAISO filed the APSA with FERC on May 23, 2014 in Docket No. ER14-2033-000 and FERC accepted the APSA effective July 23, 2014. The APSA had cost cap of $14,283,122.[164] The project began development in July 2013 and was originally scheduled for energization on May 15, 2015. CAISO received notice from the Imperial Irrigation District on November 24, 2015 exercising its right to terminate the APSA.

ISO Project Cost estimate: $25 million, produced 2013[165]

Proposed In-service Date: January 2015

MISO

Duff-Coleman
Need: efficiency

Project: MISO initiated its first solicitation process in January 2016 when it issued an RFP for a market efficiency project known as the Duff-Coleman EHV 345 kV Competitive Transmission Project, a 345-kV transmission line connecting the Duff substation in southern Indiana to the Coleman EHV substation in western Kentucky.

Bidders:

- Ameren Transmission Company of Illinois and PPL TransLink, Inc.
- Duke-American Transmission Company, LLC
- Edison Transmission, LLC
- GridAmerica Holdings, Inc.

162 CAISO, Imperial Valley Project Sponsor Selection Report, July 11, 2011, p. 3.
163 CAISO, Imperial Valley Project Sponsor Selection Report, July 11, 2011, p. 1.
164 CAISO Transmittal Letter, Docket No. ER16-508, December 11, 2015, p. 41.
165 CAISO, Imperial Valley Project Sponsor Selection Report, July 11, 2011, p. 2.

- ITC Midcontinent Development, LLC
- Midcontinent MCN, LLC
- NextEra Energy Transmission Midwest, LLC
- Republic Transmission, LLC
- Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Incorporated and Public Service Enterprise Group. Inc.
- Transource Energy, LLC
- Xcel Energy Transmission Development Company, LLC.

Winner: Republic Transmission, LLC., a partnership between Big Rivers Electric Corporation and LS Power, with a bid of $49.8 million.[166] Republic Transmission's bid included a "firm rate base cap" of $58.1 million, or $47 million in 2016 dollars. MISO stated that the firm rate base cap transfers escalation risk and administrative and general cost increase risk away from customers.

ISO Implementation Cost: $1,331,940[167]

Notes: In March 2017 Republic Transmission petitioned FERC for certain transmission rate incentives related to the Duff-Coleman project, including: 1) deferred recovery of prudently incurred pre-commercial costs through creation of a regulatory asset; 2) full recovery of prudently-incurred costs if the project is abandoned for reasons beyond Republic's control; 3) use of a hypothetical capital structure consisting of 55% debt and 45% equity until the project achieves commercial operation; and 4) 50 basis point adder to Republic's return on equity ("ROE") for participating in a RTO, subject to the overall ROE cap accepted by MISO.[168] The Commission approved Republic's request for incentives with certain restrictions in October 2017, including the establishment of a regulatory asset for pre-commercial costs.[169]

ISO Project Cost Estimate: MISO estimated project cost was $58.9 million.[170]

---

166 MISO Duff-Coleman Selection Report, December 20, 2016, p. 38.

167 MISO, *Competitive Developer Selection Process Incurred Costs*, https://cdn.misoenergy.org/Incurred%20Costs%20-%20Duff-Coleman%20EHV%20345kV82322.pdf

168 Republic Petition, March 22, 2017, Docket No. EL17-52-000, p. 2.

169 *Republic Transmission, LLC, Order Granting Petition for Declaratory Order*, 161 FERC ¶ 61,036, (October 6, 2017).

170 MISO, Duff-Coleman Selection Report, December 20, 2016, p. 5.

Hartburg Sabine

Project: 500 kV line known as Hartburg-Sabine Junction. The MISO scoping level estimated project cost was reported as $122.4 million.[171]

Bidders:

- Avangrid Networks, Inc.
- EasTex TransCo, LLC
- GridLiance Heartland, LLC
- ITC Midcontinent Development, LLC / Hunt Transmission Services, LLC
- Midwest Power Transmission Arkansas, LLC
- NextEra Energy Transmission Midwest, LLC
- Transource Energy, LLC
- Verdant Plains Electric, LLC
- Xcel Energy Transmission Development Company, LLC

Winner: NextEra Energy Transmission Midwest won the solicitation with a project implementation cost capped at $114.8 million. NextEra submitted an estimated annual transmission revenue requirement of $95.0 million.[172] The transmission revenue requirement will be capped only for the first ten years of the project's service life. Other NextEra cost caps include an ROE cap of 9.8%, an equity ratio cap of 45%, and caps on O&M for the first ten years of the project's rate recovery.

ISO Evaluation Cost: $1,137,240[173]

PJM

PJM has conducted many solicitations for new projects since implementing Order No. 1000.[174] PJM indicated in a May 2019 presentation that the RTO incurred $447,717 to evaluate 2016 Proposal Windows 1, 2, and 3 and $1,230,402 to evaluate the 2016/17 long term proposal window and Window 1 in 2017 proposals.[175] The Brattle Report only estimates cost savings for the Artificial Island solicitation.

---

171 MISO, Hartburg-Sabine Selection Report, November 27, 2018, p. 5.
172 MISO, Hartburg-Sabine Selection Report, November 27, 2018, pp. 5-6.
173 MISO, Competitive Developer Selection Process Incurred Costs, January 25, 2019.
174 *See e.g.*, Federal Energy Regulatory Commission, 2017 Transmission Metrics Staff Report (October 6. 2017) pp. 16-18.
175 PJM, *Cost Containment Status and Next Steps* (May 16, 2019) at p. 20, https://www.pjm.com/-/media/committees-groups/committees/pc/20190516/20190516-item-08-cost-containment-status-and-next-steps.ashx

Artificial Island

PJM, which uses a sponsorship model to comply with Order 1000, does not produce planning-level estimates of the transmission needs it issues solicitations for. As such, the Brattle Report uses a PSE&G bid as a "reference cost" to estimate the cost savings from the Artificial Island solicitation. Concentric identified the sources of the two figures Brattle used to estimate the savings, which Brattle claims were 60%, associated with the solicitation process. The table below summarizes these sources.

Brattle Report Artificial Island Cost Estimate Sources

"Differences in Competitive Bids and Initial Cost Estimates"	RTO/Incumbent Estimate of Project Cost ($ M)	Winning Competitive Bid ($ M)	"Cost Advantage" of Winning Bid
Brattle Figure 13	$692	$280	60%
Source	PJM Artificial Island White Paper, July 2015 at 12, referencing PSE&G's Project P2013_1-7E "New Freedom – Deans 500 and Salem-Hope Creek 500 kV lines.	PJM AI update to TEAC, March 3, 2017 at 13 ($143 M for 230 kV Line and Silver Run Substation + $132M for Hope Creek 2B Interconnection + $2M for DE Interconnection)	

The source of Brattle Report's figure for the Incumbent cost estimate is PSE&G project # P2013_1-7E.[176]

Bidders that provided supplemental responses: [177]

- Dominion High Voltage (2013-1-1A)
- Dominion High Voltage (2013-1-1C)
- Transource (2013-1-2B) (also has a "Redacted Public Power Proposal")
- Northeast Transmission Development (2013-1-5A)
- PSE&G (2013-1-7K)
- Virginia Electric and Power Company
- First Energy Corporation
- Pepco Holdings, Inc and Exelon Corporation
- Atlantic Grid Holdings LLC
- PSE&G

Winner: LS Power.

Notes: See the Artificial Island Case Study in Section 4.1 of this report.

Ap South

Need: Market Efficiency 2014/15 Long Term Proposal Window[178]

176 PJM, Artificial Island Project Recommendation, July 29, 2015, at 12.
177 *See* PJM website https://www.pjm.com/planning/competitive-planning-process/closed-artificial-island-proposals.aspx
178 PJM, Transmission Expansion Advisory Committee Market Efficiency Update, presented to the TEAC on June 9, 2016, p. 3.

Bidders:[179]

Project	Cost Estimate ($ million)	Schedule Estimate (months)
6C	$41.1	32
6D	$38.5	30
9A	$267.1	59
14A	$52.6	42
19G	$46.6	33

Winner: Project 9A- Transcource Energy (an AEP affiliate), with integration work completed by BG&E and Allegheny Power. PJM released the results of its assessment where it determined that Project 9A offered the highest cost-benefit ratio.[180] The PJM Board approved staff's recommendation on August 2, 2016. PJM executed a Designated Entity Agreement with Transource Energy on November 2, 2016.[181]

Notes: The proposed capital cost for Project 9A was $269,073,000, with upgrades on incumbent TO systems bringing the cost to $340.6 million.[182] PJM reevaluated Project 9A in four times (September 2017, February 2018, September 2018, and November 2018) and continued to find a favorable cost-benefit ratio. The updated capital cost during a third re-evaluation that found the project continued to have a favorable cost-benefit ratio, was $372.23 million.[183]

Proposed In-Service Date: 2020

NYISO

NYISO has a sponsorship model and has carried out two solicitations –Western NY and AC Transmission. NYISO does not publicly release the winning bids but instead publishes project cost estimates produced by the independent consultant Substation Engineering Co.

Western NY Public Policy

Need: Policy

Project: build a power line that would allow for increased deliveries from a major New York Power Authority hydroelectric project and bring in renewable imports from Canada.

179 PJM, PJM 2014/2015 Long Term Proposal Window Independent Cost Review White Paper, April 28, 2016, p. 1.
180 PJM, Transmission Expansion Advisory Committee Market Efficiency Update, presented to the TEAC on June 9, 2016, p. 5.
181 *PJM Interconnection, L.L.C.*, Order Accepting Subject to Condition and Suspending Proposed Agreement, 158 FERC ¶ 61,021, (January 12, 2017) at P1.
182 PJM, Transmission Expansion Advisory Committee Market Efficiency Update, presented to the TEAC on June 9, 2016, p. 3.
183 PJM Transource Independence Energy Connection Market Efficiency Project, November 15, 2018, pp. 10-11.

Bidders:

Table 2-3: Proposed Projects

Developer	Project Name	Project ID	Category	Type	Location (County/State)
NRG Dunkirk Power	Dunkirk Gas Addition	OPP02	OPPP	ST	Chautauqua, NY
North America Transmission	Proposal 1	T006	PPTP	AC	Niagara-Erie, NY
North America Transmission	Proposal 2	T007	PPTP	AC	Niagara-Erie, NY, Wyoming, NY
North America Transmission	Proposal 3	T008	PPTP	AC	Niagara-Erie, NY, Wyoming, NY
North America Transmission	Proposal 4	T009	PPTP	AC	Niagara-Erie, NY, Wyoming, NY
ITC New York Development	15NYPP1-1 Western NY AC	T010	PPTP	AC	Niagara-Erie, NY
National Grid	Moderate Power Transfer Solution	T011	PPTP	AC	Niagara-Erie, NY
National Grid	High Power Transfer Solution	T012	PPTP	AC	Niagara-Erie, NY
NYPA/NYSEG	Western NY Energy Link	T013	PPTP	AC	Niagara-Erie, NY, Wyoming, NY
NextEra Energy Transmission New York	Empire State Line Proposal 1	T014	PPTP	AC	Niagara-Erie, NY
NextEra Energy Transmission New York	Empire State Line Proposal 2	T015	PPTP	AC	Niagara-Erie, NY
Exelon Transmission Company	Niagara Area Transmission Expansion	T017	PPTP	AC	Niagara-Erie, NY

PPTP = Public Policy Transmission Project ST = Steam Turbine
OPPP = Other Public Policy Project AC = Alternating Current Transmission

Source: NYISO, Western NY Public Policy Transmission Planning Report (October 17, 2017) p. 15.

Independent Third-Party Cost Estimates for Western NY proposals:[184]

Project ID	Independent Cost Estimate: 2017 $M
T006	157
T007	278
T008	356
T009	487
T011	177
T012	433
T013	232
T014	181
T014_Alt	219
T015	159
T015_Alt	197
T017	299

Winner: NextEra Energy Transmission New York, Inc., ("NEETNY") Empire State Line Project 1 (T014).[185] The project includes a new Dysinger 345 kV substation, a new East Stolle 345 kV 17 switchyard, and a 345 kV line connecting Dysinger and East Stolle substations, with a 700 MVA 345 kV phase angle regulator at the Dysinger switchyard. All facilities will predominantly use existing rights-of-way.[186]

Notes: NEETNY filed an application with the New York State Public Service Commission in August 2018 for a certificate of environmental compatibility and public need to build, operate, and maintain the Empire State Line Project. NEETNY also made a filing with FERC to establish the architecture for a formula rate and requested ROE adders, which FERC approved in November 2017.[187]

Proposed in-service date: June 2022.[188]

AC Transmission

Need: Policy

Project: Two new 345-kV transmission lines to address persistent transmission congestion at the Central East (Segment A) electrical interface and Upstate New York/Southeast New York (UPNY/SENY, or Segment B).[189]

Window: February 29, 2016 - April 29, 2016

Bidders: Six Developers submitted 16 project proposals

184 NYISO, Western New York Public Policy Transmission Planning Final Report, October 17, 2017, p. 38.
185 NYISO Press Release, *NYISO Selects NextEra Transmission Project to Increase Access to Hydro Power*, October 17, 2017.
186 NextEra Energy Transmission New York, Inc. Application for a Certificate of Environmental Compatibility and Public Need, New York State Department of Public Service Case No. 18-T-0499, Testimony of Michael Lanon, August 10, 2018, p. 4.
187 *NextEra Energy Transmission New York, Inc.*, 161 FERC ¶ 61,138 (November 3, 2017).
188 Transmission Hub, https://www.transmissionhub.com/articles/2018/08/neetny-seeks-regulatory-approval-in-new-york-of-345-kv-empire-state-line-project.html
189 NYISO, AC Transmission, AC Transmission Public Policy Transmission Need Viability and Sufficiency Assessment, September 16, 2016.

AC Transmission Proposals

Developer	Project Name	Category	Type	Location	Size
National Grid / Transco	New York Energy Solution Seg. A	PPTP	AC Transmission	Segment A	N/A
National Grid / Transco	New York Energy Solution Seg. B	PPTP	AC Transmission	Segment B	N/A
NextEra Energy Transmission New York	Enterprise Line: Segment A	PPTP	AC Transmission	Segment A	N/A
NextEra Energy Transmission New York	Enterprise Line: Segment B	PPTP	AC Transmission	Segment B	N/A
NextEra Energy Transmission New York	Enterprise Line: Segment B-Alt	PPTP	AC Transmission	Segment B	N/A
North America Transmission / NYPA	Segment A +765 kV	PPTP	AC Transmission	Segment A	N/A
North America Transmission / NYPA	Segment A Base	PPTP	AC Transmission	Segment A	N/A
North America Transmission / NYPA	Segment A Double Circuit	PPTP	AC Transmission	Segment A	N/A
North America Transmission / NYPA	Segment A Enhanced	PPTP	AC Transmission	Segment A	N/A
North America Transmission / NYPA	Segment B Base	PPTP	AC Transmission	Segment B	N/A
North America Transmission / NYPA	Segment B Enhanced	PPTP	AC Transmission	Segment B	N/A
ITC New York Development	16NYPP1-1A AC Transmission	PPTP	AC Transmission	Segment A	N/A
ITC New York Development	16NYPP1-1B AC Transmission	PPTP	AC Transmission	Segment B	N/A
AvanGrid	Connect New York Recommended	PPTP	HVDC	Segments A and B	1000 MW
AvanGrid	Connect New York Alternative	PPTP	HVDC	Segments A and B	1000 MW
GlidePath	Distributed Generation Portfolio	OPPP	Generation	Orange, Ulster, Putnam, Greene, NY	112 MW

PPTP: Public Policy Transmission Project   OPPP: Other Public Policy Project

Source: NYISO, ESPWG/TPAS Presentation, September 26, 2016 [190]

Third party estimate of AC Transmission Proposal Costs

Table A-3: Cost per MW Ratio

Project	Segment B Independent Cost Estimate (2018 $M)	Incremental UPNY/SENY (MW)	Cost per MW
T027+T019	$479	2,100	**0.228**
T027+T022	$373	1,600	**0.233**
T027+T023	$424	1,550	**0.274**
T027+T029	$422	1,475	**0.286**
T027+T030	$441	1,600	**0.276**
T027+T032	$536	1,525	**0.351**

The results show that T019 has the lowest Cost per MW ratio of all the Segment B projects.

Source: NYISO, AC Transmission, Revised Draft Report Addendum.[191]

Winners**:**

<u>Segment A</u>**:** NYISO staff recommended and the NYISO Board approved Project T027, a joint proposal by North America Transmission and the New York Power Authority to construct a double-circuit 345-kV line from Edic to New Scotland.

190 NYISO, AC Transmission, AC Transmission Public Policy Transmission Need Viability and Sufficiency Assessment, September 26, 2016, p. 10.

191 NYISO, AC Transmission Public Policy Transmission Planning Report Addendum, Draft, February 20, 2019, p. 11.

Segment B: NYISO staff recommended a joint proposal by North America Transmission and the New York Power Authority (project T029). However, the NYISO Board revised the NYISO staff's selection for Segment B, and selected a competing proposal by National Grid and New York Transco (project T019). The NYISO Board determined that project T019 "demonstrated superior performance across a broader range of metrics when compared to Project T029 and the other proposed Segment B projects, including, significantly, providing additional transfer capability across the UPNY/SENY transmission interface."[192]

SPP

To date, SPP's integrated transmission planning process has only recommended one project for solicitation, a 21-mile 115 kV line from North Liberal to Walkemeyer Station. SPP hires a third-party industry expert panel to review proposals for new transmission projects.

Walkemeyer

Bidders: The Walkemeyer solicitation had 11 total proposals with costs ranging from $17.1 million to $7.5 million.[193]

Winner: Mid Kansas Electric Company, with a total project cost of $8.3 million.[194] All other project bidders remain confidential. The Walkemeyer project was canceled in June 2016 due to declining load.

ISO Project Cost Estimate: $17.5 million[195]

ISO Evaluation Cost: $522,196[196]

---

192 NYISO, Notice of Board of Directors' Decision on Approval of AC Transmission Public Policy Transmission Planning Report and Selection of Public Policy Transmission Projects (April 8, 2019) at 4.
193 Industry Expert Panel Recommendation Report, RFP-000001 (Walkemeyer - North Liberal 115kV) April 12, 2016, p. 4, Table 1.
194 SPP 2016 Q3 Quarterly Project Tracking Report, p. 7.
195 SPP, MOPC Report to Board of Directors / Members Committee, April 28, 2015, slide 51.
196 SPP Strategic Planning Committee – Order 1000 Workshop Meeting Minutes (July 7, 2016), p. 1.

APPENDIX D: COST CAPS

Cost caps have been included in multiple ISO/RTO solicitation proposals and comprise a broad range of containment measures. The following provides an overview of bidders' proposed cost caps in each RTO or ISO that held solicitations.

CAISO

HENRY ALLEN TO ELDORADO (DESERTLINK)[197]

Incentive rate treatments:

- Deferred recovery of prudently incurred pre-commercial costs through creation of a regulatory asset
- Full recovery of prudently incurred costs if the project is abandoned for reasons beyond DesertLink's control
- Use of a hypothetical capital structure consisting of 50% debt and 50% equity until the project achieves commercial operation
- 50-basis point RTO Participation adder subject to the overall ROE not exceeding the ROE cap commitment in DesertLink's Project proposal (9.8%)

MISO

DUFF-COLEMAN (REPUBLIC TRANSMISSION)

- "Firm rate base cap" of $58.1 million, or $47 million in 2016 dollars.[198]
- MISO discussed that the firm rate base cap transfers escalation risk and administrative and general cost increase risk away from customers.

FERC RATE INCENTIVES:[199]

- Deferred recovery of prudently incurred pre-commercial costs through creation of a regulatory asset;
- Full recovery of prudently incurred costs if the Project is abandoned for reasons beyond Republic's control;

[197] *DesertLink, LLC*, Order on Transmission Owner Tariff and Formula Rate Proposal, Establishing Hearing and Settlement Judge Procedures and Dismissing Request for Rehearing, 161 FERC ¶ 61,126 (October 31, 2017). Note, not all CAISO project cost caps are discussed herein.

[198] Duff-Coleman Selection Report, December 20, 2016, p. 38

[199] *Republic Transmission, LLC*, Order Granting Petition for Declaratory Order, 161 FERC ¶ 61,036 (October 6, 2017).

- Use of a hypothetical capital structure consisting of 55% debt and 45% equity until the project achieves commercial operation, which ratio is consistent with Republic's commitment and accepted by MISO; and
- 50-basis point adder to Republic's ROE for participating in a RTO, subject to the overall return on equity cap (inclusive of incentives) Republic committed to as part of its project proposal submitted to and accepted by MISO.[200,201]

Other proposals offer cost caps such as caps on ROE, capital structure, implementation costs, O&M costs, inflation rate assumptions, and other rate concessions.

HARTBURG-SABINE (NEXTERA ENERGY TRANSMISSION MIDWEST)

Project implementation cost capped at $114.8 million[202]

Estimated annual transmission revenue requirement of $95.0 million or $11 million below the median estimate, capped for the first 10 years of project's recovery lifetime.[203]

ROE cap of 9.8%, an equity ratio cap of 45%, and caps on O&M for the first ten years of the project's rate recovery.

Other proposals' cost caps included caps on total implementation cost, foregoing AFUDC, foregoing CWIP, a line route changes from the Texas siting authority, ROE and equity ratio caps, and caps on annual transmission revenue requirement and O&M expenses that range from 5 years to 40 years.[204]

SPP

WALKEMEYER (MID KANSAS ELECTRIC COMPANY)

- The Walkemeyer project was canceled in June 2016 due to declining load.
- Cost containment ability and experience metric was considered in evaluation of each RFP

Other proposals included various cost cap provisions such as total cost caps, ROE and equity ratio caps, and rate base caps. The proposals also included a mix of provisions for cost overrun pass-throughs such as capitalized property taxes.

---

200 Republic Transmission, LLC Transmittal Letter, Docket No. EL17-52-000, March 22, 2017, p. 2.

201 *Republic Transmission, LLC,* Order Granting Petition for Declaratory Order, 161 FERC ¶ 61,036. Docket No. EL17-52-000. (October 6, 2017). Republic argued that the requested incentives "are narrowly tailored to the risks faced in the development and construction of the Project and will allow Republic to attract the capital necessary to move forward with the Project in the most efficient and cost-effective manner." The FERC approved Republic's request for incentives with certain restrictions in October 2017, including the establishment of a regulatory asset for pre-commercial costs.

202 MISO, Hartburg-Sabine Selection Report, November 27, 2018, p. 5.

203 MISO, Hartburg-Sabine Selection Report, November 27, 2018, p. 5-6.

204 Hartburg-Sabine Selection Report, November 27, 2018, p. 20.

NYISO

WESTERN NEW YORK PUBLIC POLICY

- FERC ROE incentives[205]
- NYISO did not take cost caps into account in its selection process noting it is not required by Order No. 1000.

AC PUBLIC POLICY TRANSMISSION NEEDS

- NYSPC highly encouraged cost containment incentives, noting that the developer should share in some portion of cost overruns should they occur. Similarly, the developer should share in any cost savings should they occur.[206]

PJM

ARTIFICIAL ISLAND (NORTHEAST TRANSMISSION DEVELOPMENT)

- Northeast Transmission Development received FERC-approved ROE, debt/equity structure, abandonment recovery, and cost containment provisions.
- Construction cost cap subject to certain exemptions.

AP SOUTH (TRANSOURCE)

- Project cost cap of $197.1 million, with an annual 3% compounded escalation adjustment to account for inflation as measured from the bid submission date of February 27, 2015 and the Project In-Service Date in 2020.
- FERC-approved ROE plus incentives on the costs incurred for the Project up to the Estimated Project Cost;
- FERC-approved ROE on the costs incurred for the Project above the Estimated Project Cost, but shall forego any return on equity incentives approved by FERC (including the RTO participation adder) for the project cost portion that exceeds the Estimated Project Cost; and
- Cap on actual equity content of no greater than 50% for the Project, once permanent financing is in place.
    - Transource shall be granted relief from this commitment if the capital market conditions do not remain normal and the Transource Subsidiaries do not have the ability to finance these transmission projects with the proposed capital structure.

---

205 *NextEra Energy Transmission New York, Inc.*, 161 FERC ¶ 61,138 (November 3, 2017) at P 2.
206 State of New York Public Service Commission, Case 12-T-0502, *et al.* (December 17, 2015) at pp. 47-48.

APPENDIX E: ORDER NO. 1000 BACKGROUND

In July 2011, the Federal Energy Regulatory Commission issued a final rule entitled *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*.[207] The Commission subsequently clarified and revised the Order No. 1000 requirements in Order No. 1000-A[208] in May 2012 and Order No. 1000-B[209] in October 2012. It is important to understand the scope of FERC's Order No. 1000 reforms,[210] specifically what they did and did not require with respect to transmission planning. Regarding transmission planning, Order No. 1000 required public utility transmission providers, such as Independent System Operators ("ISOs") or Regional Transmission Organizations ("RTOs"), to:

- Participate in a regional transmission planning process that produces a regional transmission plan;
- Amend its Open Access Transmission Tariff ("OATT") to describe procedures to consider transmission needs driven by public policy requirements established by local, state, or federal laws or regulations in the local and regional transmission planning processes;
- Remove federal ROFRs from Commission-jurisdictional tariffs and agreements for certain new transmission facilities; and
- Improve coordination between neighboring transmission planning regions for new interregional transmission facilities.[211]

Order No. 1000 also established regulations related to allocating the costs of new transmission facilities selected through a regional planning process to subregions of a planning region (e.g., zones). However, these cost allocation requirements are not the focus of this report and are not discussed herein. Order No. 1000 also required that the regional transmission planning process result in a regional transmission plan that satisfies the transmission planning requirements set forth in Order No. 890: 1) coordination; 2) openness; 3) transparency; 4) information exchange; 5) comparability; 6) dispute resolution; and 7) economic planning.[212]

The Order No. 1000 requirements were never intended to open all new FERC-jurisdictional transmission facilities – or some arbitrary percentage of them – to solicitation. Rather, the Order No. 1000 requirements

---

207 Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, 136 FERC ¶ 61,051 (July 21, 2011) (Order No. 1000).

208 Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, 139 FERC ¶ 61,132 (May 17, 2012) (Order No. 1000-A).

209 Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, 141 FERC ¶ 61,044 (October 18, 2012) (Order No. 1000-B).

210 This report refers to the requirements promulgated in Order No. 1000, as clarified in Order Nos. 1000-A and 1000-B, collectively as "Order No. 1000 requirements" or "Order No. 1000". Distinctions are only made for purposes of citation.

211 Order No. 1000 Summary.

212 Order No. 1000 at PP 146, 151. These transmission planning principles are explained in Order No. 890 (*Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241, order on reh'g, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), order on reh'g, Order No. 890-B, 123 FERC ¶ 61,299 (2008), order on reh'g, Order No. 890-C, 126 FERC ¶ 61,228, order on clarification, Order No. 890-D, 129 FERC ¶ 61,126 (2009)).

were discretely focused on a subset of new transmission facilities. Specifically, Order No. 1000's transmission planning requirements require public utility transmission providers to adopt transparent and not unduly discriminatory criteria for selecting *new* transmission facilities in a *regional* transmission plan for *purposes of cost allocation*.[213] As such, the Order No. 1000 requirements only applies to transmission facilities that meet all three of the following requirements:

- new facilities (i.e., not upgrades to existing facilities)
- selected as part of a regional transmission plan (as opposed to a local plan)
- allocated regionally (i.e., not allocated solely within a single zone).

The three requirements are discussed in turn below. In promulgating the Order No. 1000 requirements, the Commission determined it was necessary, in certain circumstances, to eliminate the federal right of first refusal ("ROFR") afforded to incumbent transmission owners from FERC-jurisdictional tariffs and agreements to ensure the selection of new transmission facilities through the regional planning process for purposes of cost allocation does not impede a nonincumbent transmission developer's participation in regional transmission planning.[214] Practically speaking, removing the federal ROFR from FERC-jurisdictional tariffs and agreements (e.g., ISO/RTO tariffs or TO participation agreements) permitted nonincumbent transmission developers to propose alternative solutions in the regional transmission planning process. The Order No. 1000 requirements only apply to certain transmission projects, and the ISO/RTO tariffs that the Commission ultimately approved to comply with Order No. 1000 requirements retain an incumbent TO's federal ROFR for other transmission projects. The transmission projects that are subject to the Order No. 1000 requirements – new facilities that are selected in a regional plan with costs that are allocated regionally – are discussed below.

New transmission facilities

Order No. 1000 applies to new facilities, not upgrades. As such, the Order No. 1000 requirements only eliminated the federal ROFR from FERC-jurisdictional tariffs and agreements for *new* transmission facilities selected in a regional plan for purposes of cost allocation.[215] Accordingly, incumbent TOs retained a federal ROFR for upgrades to their own transmission facilities .[216] For example, the Commission stated that the Order No. 1000 requirements:

> [D]o not affect the right of an incumbent transmission provider to build, own and recover costs for upgrades to its own transmission facilities, such as in the case of tower change outs or reconductoring, regardless of whether or not an upgrade has been selected in the regional transmission plan for purposes of cost allocation. In other words, an incumbent transmission

[213] See e.g., Order No. 1000-A at P 455 and Order No. 1000-B at P 59.
[214] See e.g., Order No. 1000 at PP 261, 320. See also Order No. 1000 at P 261.
[215] Order No. No. 1000-A at 415. See also Order No. 1000-B at P 41.
[216] The NYISO tariff and agreements did not contain any federal ROFRs and thus were not required to modify any ROFR pursuant to Order No. 1000 requirements.

provider would be permitted to maintain a federal right of first refusal for upgrades to its own transmission facilities.[217]

In Order No. 1000-A, the Commission clarified that an upgrade is an "improvement to, addition to, or replacement of a part of, an existing transmission facility" and does not refer to an entirely new transmission facility.[218]

Facilities selected in a regional transmission plan

ISO/RTO transmission planning involves both a local aspect, which generally occurs within a given incumbent TO's distribution service territory, and a regional aspect related the integrated operation of the local distribution service territories within a larger planning region (e.g., ISO/RTO). As noted above, the Order No. 1000 requirements only applied to new transmission facilities that are *selected through a regional transmission plan for the purposes of cost allocation*. As such, Order No. 1000 did not require ISOs/RTOs to eliminate an incumbent TO's federal ROFR to construct local transmission facilities, where the Commission defined a "local transmission facility" as a "transmission facility located solely within a public utility transmission provider's retail distribution service territory or footprint that is not selected in the regional transmission plan for purposes of cost allocation."[219]

The Commission explicitly recognized the fact that incumbent TOs must comply with reliability standards and have an obligation to serve customers. Accordingly, the Commission affirmatively stated that the Order No. 1000 requirements were not intended to disrupt a TO's local planning processes:

> We clarify that our actions today are not intended to diminish the significance of an incumbent transmission provider's reliability needs or service obligations. Currently, an incumbent transmission provider may meet its reliability needs or service obligations by building new transmission facilities that are located solely within its retail distribution service territory or footprint. The Final Rule continues to permit an incumbent transmission provider to meet its reliability needs or service obligations by choosing to build new transmission facilities that are located solely within its retail distribution service territory or footprint and that are not submitted for regional cost allocation.[220]

Order No. 1000 did not create a categorical exemption from eliminating a jurisdictional federal ROFR for reliability projects selected through the regional planning process.[221] However, the Commission stressed the importance of the incumbent TO's responsibility to maintain reliability in its service territory. Specifically, Order No. 1000 states that "nothing herein restricts an incumbent transmission provider from developing a local transmission solution that is not eligible for regional cost allocation to meet its reliability needs or service obligations in its own retail distribution service territory or footprint."[222]

---

217 Order No 1000 at P 319. *See also* Order No. 1000-A at P 426.
218 Order No. 1000-A at P 426.
219 Order No. 1000 at P 63.
220 Order No. 1000 at P 262.
221 Order No. 1000-A at P 428.
222 Order No. 1000 at P 329.

The Commission also recognized that reliability issues may need be addressed quickly and that, "one function of the regional transmission planning process is to identify those transmission facilities that are needed to meet identified needs on a timely basis and, in turn, enable public utility transmission providers to meet their service obligations."[223] For example, Order No. 1000 required public utility transmission providers to have procedures in place in the event that a transmission project selected through the regional planning process experienced development delays that could threaten an incumbent TO's obligation to meet its reliability needs or service obligations.[224]

The Commission also recognized the need to satisfy reliability requirements in a timely matter in the Order No. 1000 compliance orders it issued for the six jurisdictional ISOs/RTOs.[225] As discussed further below in the Order 1000 compliance section of this Appendix, the Commission has accepted ISO/RTO tariff provisions that retain, in certain circumstances, an incumbent TO's federal ROFR to construct a transmission project in that TO's service territory if a given project is needed by a certain date for reliability purposes.

For example, when the Commission approved PJM's Order No. 1000 compliance filing to designate the incumbent TO as the transmission developer of "Immediate Need Reliability Projects," which are projects needed in three years or less. The Commission stated "We agree with PJM that there may be instances in which it may not be feasible to hold a competitive solicitation process to solve a reliability violation. Thus, to avoid delays in the development of transmission facilities needed to resolve a time-sensitive reliability criteria violation, we find that it is just and reasonable to include a class of transmission projects that are exempt from the competitive solicitation."[226] The Commission approved similar provisions in ISO-NE and SPP.

Projects with regionally allocated costs

The Commission Order No. 1000 requirements only apply to new transmission projects that are selected through a regional planning process and for which the costs will be allocated to more than one zone. The Commission clarified in Order No. 1000-A that Order No. 1000 "does not require elimination of a federal right of first refusal for a new transmission facility if the regional cost allocation method results in 100% of the facility's cost being allocated to the public utility transmission provider in whose retail distribution service territory or footprint the facility is to be located."[227] In Order No. 1000-A the Commission further clarified that the phrase "selected in a regional transmission plan for purposes of cost allocation" "excludes a new transmission facility if the costs of that facility are borne entirely by the public utility transmission provider in whose retail distribution service territory or footprint that new transmission facility is to be located."[228] The Commission also clarified in Order No. 1000-B that the act of selecting a new transmission facility in the

223 Order No. 1000 at P 264.
224 Order No. 1000 at P 329. *See also* Order No. 1000-A at P 428.
225 ISO/RTO Order No. 1000 compliance orders, which occurred over several iterations, are available here: https://www.ferc.gov/industries/electric/indus-act/trans-plan/regional.asp?csrt=917136660019168714
226 PJM Interconnection, L.L.C., 142 FERC ¶ 61,214 (March 22, 2013) at P 247.
227 Order No. 1000-A at P 423.
228 Order No. 1000-A at P 423.

regional transmission plan for purposes of cost allocation triggers the applicability and attendant requirements of Order No. 1000.[229] Accordingly, transmission facilities that are not selected through a regional planning process (e.g., selected through a local planning process) and facilities that are selected through a regional planning process but not for purposes of regional cost allocation are not subject to Order No. 1000 requirements.

ROFR and rights-of-way granted by others

FERC only has jurisdiction over ROFRs, to the extent they exist, in FERC-jurisdictional tariffs and agreements. However, an incumbent TO may have a ROFR to construct a transmission project within its service territory that is granted by a state or local authority. The Commission clarified in Order No. 1000-A that the requirement to eliminate a federal ROFR in certain circumstances does not preempt state law because the Order No. 1000 requirements are "focused on Commission-jurisdictional tariffs and agreements, and are not intended to preempt state or local laws or regulations."[230] With respect to rights of way in particular, the Commission explained that Order No. 1000 requirements are "not intended to alter an incumbent transmission provider's use and control of its existing rights-of-way"[231] and that the requirements do not "grant or deny transmission developers the ability to use rights-of-way held by other entities, even if transmission facilities associated with such upgrades or uses of existing rights-of-way are selected in the regional transmission plan for purposes of cost allocation."[232]

229 "[O]nce a new transmission facility is selected in the regional transmission plan for purposes of cost allocation, it is no longer a local transmission facility exempt from the requirements of Order Nos. 1000 and 1000-A regarding the removal of federal rights of first refusal." Order No. 1000-B at P 52.

230 Order No. 1000-A at P 379.

231 Order No. 1000 at P 319.

232 Order No. 1000 at P 319.