UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection	)	**Docket No. RM21-17-000**
Transmission Planning and Cost Management	)	**Docket No. AD22-8-000**
Joint Federal-State Task Force on Electric Transmission	)	**Docket No. AD21-15-000**

SUPPLEMENTAL COMMENTS OF
DEVELOPERS ADVOCATING TRANSMISSION ADVANCEMENTS

Pursuant to Rule 212[1] of the Federal Energy Regulatory Commission's ("FERC" or "Commission") Rules of Practice and Procedure, Developers Advocating Transmission Advancements ("DATA")[2] hereby respectfully move for leave to submit the following supplemental comments in response to the Commission's Notice of Proposed Rulemaking (NOPR), "Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection"[3] as well as the Commission's Notice Inviting Post-Technical Conference Comments.[4] These supplemental comments include an attached

[1] 18 C.F.R. § 385.212 (2018).
[2] DATA is a coalition of transmission-owning utilities consisting of Ameren Services Company, Eversource Energy, Exelon Corporation, ITC Holdings Corp., National Grid USA, Public Service Electric and Gas Company, and Xcel Energy.
[3] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 179 FERC ¶ 61,028 (2022) ("NOPR").
[4] *Transmission Planning and Cost Management and Joint Federal-State Task Force on Electric Transmission*, Notice Inviting Post-Technical Conference Comments, Docket Nos. AD22-8-000, AD21-15-000 (Dec. 23, 2022) ("Notice").

whitepaper entitled "Revisiting the Evidence on Cost Savings from Transmission Competition" ("Whitepaper"), which presents additional empirical evidence related to the experience with transmission projects selected through competitive solicitations in the United States following FERC Order No. 1000.

I. GOOD CAUSE EXISTS TO ACCEPT THESE SUPPLEMENTAL COMMENTS

These supplemental comments and Whitepaper will assist the Commission's decision-making process by offering additional evidence related to real-world experience with transmission projects developed through competitive solicitations stemming from the requirements of Order No. 1000, which is a central issue to the NOPR docket.[5] The data and analysis presented offer new insights about the results of Order No. 1000 solicitations because more mature information has become available, including in the period since initial and reply comments were submitted in the NOPR docket, as competitively developed projects reach later stages of development and enter service. Thus, these supplemental comments contain unique evidence, which is neither repetitive nor duplicative of any other evidence submitted in the NOPR proceeding, nor the Commission's other docketed proceedings captioned above, that will help the Commission finalize any future rulemaking.[6] Therefore, DATA respectfully requests that the Commission accept these supplemental comments.

---

[5] *See, e.g.*, NOPR at PP 335-382 (proposing to modify the Commission's categorical finding in Order No. 1000 related to federal rights of first refusal and proposing to establish the possibility of certain conditional rights of first refusal), *id.* at PP 408-409 (proposing a right of first refusal for "right-sized" transmission projects). *See also Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection,* Advance Notice of Proposed Rulemaking, 176 FERC ¶ 61,204 (2021) ("ANOPR") at P 37 (seeking to understand how the right of first refusal policies of Order No. 1000 have shaped transmission development patterns). For completeness, DATA is also respectfully requesting to submit these Supplemental Comments in response to the Notice, since the issue of Order No. 1000 competitive solicitations has been raised in those dockets by some parties. *See, e.g.*, Post-technical Conference Comments of the R Street Institute, Docket Nos. AD22-8-000, AD21-15-000, at Appendix 1, n. 38 (Mar. 23, 2023).

[6] *See, e.g.*, *Algonquin Gas Transmission, LLC,* 154 FERC ¶ 61,048 at P 2 n.6 (2016) (accepting unauthorized

II. MATURE DATA INVALIDATES PRIOR EVIDENCE SHOWING COST SAVINGS FROM COMPETITIVELY DEVELOPED PROJECTS

In 2011, as part of Order No. 1000, FERC introduced competition for certain transmission projects expecting that, notwithstanding the delay and other complications in developing these projects, the result would be savings for customers. Owing to the extended timelines associated with compliance, implementation, and transmission development generally, evidence against which to test the Commission's hypothesis has been limited. However, with more than a decade having elapsed since the issuance of Order No. 1000, the body of available evidence is accumulating as competitively-sourced projects progress through the development process, which creates opportunities for analysis and learning from real-world experience.

Only a single study has been completed to quantitatively support the assertion that Order No. 1000 solicitations deliver cost savings. This study was completed in 2019 ("2019 Report")[7] and has been widely referenced, including by the Commission.[8] The 2019 Report was built on data available at the time and concluded, based on estimated project costs, that such competition could be expected to lead to cost savings of 20-30 percent.

The attached Whitepaper uses the same methodology and cost baselines as used in the 2019 Report, but updates project costs with the most current data, including actual final cost figures when available.[9] The resulting analysis shows that, rather than Order No. 1000-mandated competition leading to cost savings, final costs for projects selected through competitive

---

pleading because it aided in the decision-making process); *Dominion Cove Point LNG LP*, 118 FERC ¶ 61,007 at P 10 (2007) (accepting unauthorized pleading because it assisted in the decision-making process).

[7] The Brattle Group, *Cost Savings Offered by Competition in Electric Transmission*, April 2019 ("2019 Report").

[8] *See, e.g.*, NOPR at FN 60.

[9] Nothing in this filing should be construed as minimizing other concerns raised about the 2019 Report at the time or as validating the approach taken by the authors of that report – which, among other things, tended to bias the results towards higher calculated savings from competitive solicitations. Rather, this comment and the attached Whitepaper attempt to assess what the same approach would tell us now, with the benefit of new information, regardless of concerns regarding the underlying methodology. For a complete discussion of the critiques of the 2019 Report, see Concentric Energy Advisors, Inc., *Building New Transmission: Experience To-Date Does Not Support Expanding Solicitations*, June 2019.

solicitations tend to ***exceed*** cost baselines by at least 6 percent. Furthermore, with certain reasoned adjustments, average baseline exceedances are calculated in the 12-19 percent range. Thus, by the reasoning of the 2019 Report – which concluded that competition in transmission development would save customers 20-30 percent as compared with baselines – this updated analysis supports the conclusion that transmission competition may lead customers to experience 12-19 percent ***higher costs*** for competed projects. These outcomes diverge markedly from previously-asserted claims of ***cost savings*** flowing from competition, savings that quite clearly have not materialized. The 2019 Report also described the potential risk-reducing benefits of costs caps offered as part of many proposals in transmission solicitations. However, review of now-available data shows that competitively developed projects with cost caps in winning bids tend to significantly exceed those cost caps.

The analysis presented in the Whitepaper offers three key conclusions regarding the outcomes of competitive solicitations for transmission projects under Order No. 1000:

- Rather than delivering savings to customers, projects resulting from Order No. 1000 solicitations have experienced costs that exceed cost baselines by at least 6 percent on average, and potentially by as much as 12-19 percent on average.
- Winning bids for projects resulting from competitive process are not good indicators of final project costs, as recoverable costs for these projects tend to exceed the cost of winning proposals considerably.
- Cost caps for projects resulting from competitive processes do not appear to offer meaningful cost containment protections for customers, as final recoverable project costs for projects with cost caps tend to exceed capped amounts.

These insights also offer critical perspectives that should aid the Commission in understanding past and future claims regarding the benefits of competition in transmission development and can inform the broader debate around the Commission's competitive transmission policies and whether they deliver promised benefit to customers. Specifically, evidence purporting to show the benefits of Order No. 1000 solicitations should be discounted if it is (1) based on winning bids, (2) based on cost caps, or (3) based on early-stage cost estimates.

Absent evidence of savings and other benefits from competition in transmission development, one must consider the significant costs of delay and implementation, the negative impact on collaborative planning, and the general disfunction introduced from Order No. 1000 competitive processes.[10] The Commission must meaningfully grapple with this evidence and cannot continue to support competition for competition's sake, particularly where competition stands in the way of efficient transmission development.

III. CONCLUSION

For the foregoing reasons, DATA respectfully requests that the Commission grant leave to file these supplemental comments and that the Commission consider mature data and updated analysis regarding claims of savings stemming from Order No. 1000 solicitations when issuing any final rule in this and related dockets.

As stated previously, DATA shares the Commission's desire to see transmission infrastructure built expeditiously and cost effectively (and, of course, reliably) as a critical pillar to meet carbon reduction goals and to ensure reliable and cost-effective transmission service as

[10] *See, e.g.*, Comments of Developers Advocating Transmission Advancements, FERC Docket No. RM21-17-000 (Aug. 17, 2022). *See also* Reply Comments of Developers Advocating Transmission Advancements, FERC Docket No. RM21-17-000 (Sept. 19, 2022).

the energy transition unfolds. DATA members are an ally in this journey, with a proven track-record of designing and building transmission to serve customer and State goals.

Respectfully submitted,

/s/ *Lisa B. Luftig*
Lisa B. Luftig
Assistant General Counsel
Exelon Corporation
701 Ninth Street, NW
Washington, DC 20068
lisa.luftig@exeloncorp.com

* Filing on behalf of DATA

Dated: December 15, 2023

Supplemental Comments of Developers Advocating Transmission Advancements
December 15, 2023

Attachment:
Whitepaper

WHITEPAPER

REVISITING THE EVIDENCE ON COST SAVINGS FROM TRANSMISSION COMPETITION

DEVELOPERS ADVOCATING TRANSMISSION ADVANCEMENTS

Ameren Services Company

Eversource Energy

Exelon Corporation

ITC Holdings Corp

National Grid USA

Public Service Electric and Gas Company

Xcel Energy

December 2023

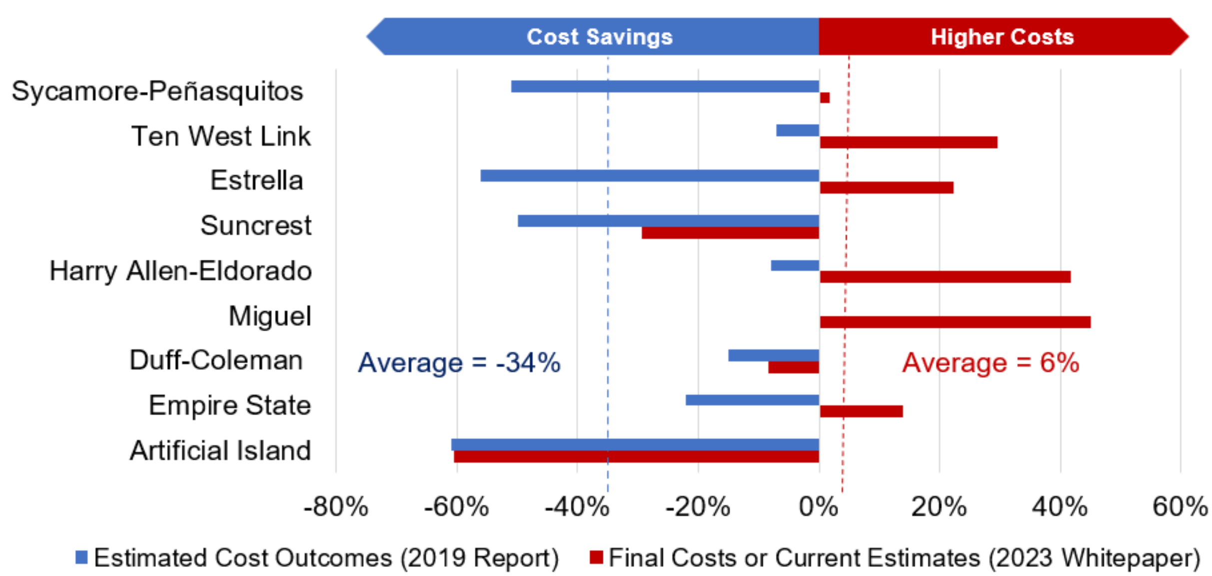
Executive Summary

The benchmark study advancing the assertion that Order No. 1000 competitive solicitations deliver cost savings to customers was completed in 2019. It relied on data available at the time and concluded, based on estimated project costs, that such competitive solicitations could be expected to lead to cost savings of 20-30%. This whitepaper uses the same methodology and cost "Baselines" from the 2019 Report but updates project costs with the most current data, including actual final cost figures. The resulting analysis reveals that, rather than Order No. 1000 competitive solicitations leading to cost savings, final costs for projects selected through competitive solicitations tend to *exceed* cost Baselines by at least 6% (see Figure 1). Furthermore, with certain reasoned adjustments, recoverable costs of competitive transmission projects, on average, exceed cost Baselines by 12-19%.

The 2019 Report also described the potential risk-reducing benefits of costs caps offered as part of many proposals in Order No. 1000 competitive solicitations. However, review of now-available data shows that competitively developed projects with cost caps in winning bids have exceeded those cost cap levels by 57-67% on average. Updated cost information also shows that competitively developed projects exceed the cost expectations in winning bids by 59-66% on average.

These results support reexamination of conclusions (1) that Order No. 1000 solicitations yield cost savings for customers, and (2) that cost caps resulting from competitive processes provide meaningful cost containment protections for customers. This review also underscores the point that claims of cost savings to customers based on winning bids from Order No. 1000 competitive solicitations, or based on cost caps, or based on early-stage cost estimates, should be significantly discounted.

Figure 1: Direct Comparison of Estimated Cost Savings from 2019 Report (blue) to Updated Cost Savings with Current Project Cost Data (red)



I. Introduction

In 2011, as part of Order No. 1000, the Federal Energy Regulatory Commission ("FERC") introduced competition for certain transmission projects. This requirement was based largely on the theory that introducing competition in the development of electric transmission would lead to lower costs for customers and would foster innovation in the identification of transmission solutions. Owing to the extended timelines associated with regional compliance, process implementation, and transmission development generally, data against which to test the Commission's hypothesis has been limited. However, with more than a decade having elapsed since the issuance of Order No. 1000, the evidence is accumulating and the reality is becoming clearer.

To date, the primary quantitative analysis supporting the cost savings of Order No. 1000 solicitations is a report prepared by The Brattle Group in 2019 ("2019 Report" or "Report"). Based on data available at the time, the 2019 Report concluded that expanding Order No. 1000 competitive processes could yield 20-30% savings compared to developing transmission projects under a paradigm where incumbent transmission owners build subject to a right of first refusal ("ROFR").[1] The 2019 Report also described the potential risk-reducing benefits of cost caps offered as part of many proposals in transmission solicitations.[2] The 2019 Report has been widely referenced when touting the benefits of Order No. 1000 competitive processes and the potential savings they offer, especially in the context of the significant levels of transmission investment expected to support the energy transition.

One of the challenges faced by the authors of the 2019 Report was that very few Order No. 1000 competitive transmission projects had been completed at the time. Significantly, final project cost data was not available. To manage this, the analysis in the 2019 Report relied on then-current cost estimates for many of the projects analyzed,[3] comparing those contemporaneous estimates (with some adjustments) to initial project cost estimates ("Baselines") to calculate expected cost savings. Now, however, better data is available. Many of the projects referenced in the 2019 Report's analysis have had their fate resolved – either through completion or cancellation of some form – and the need to rely heavily on early-stage cost estimates is behind us.[4]

[1] *See* The Brattle Group, *Cost Savings Offered by Competition in Electric Transmission*, April 2019, p. 1 ("2019 Report").

[2] *See, e.g.*, 2019 Report, p.16.

[3] Several critiques of the 2019 Report were raised at the time of its publication, including the reliance on planning level cost estimates and the use of non-final cost data. *See* Concentric Energy Advisors, Inc., *Building New Transmission: Experience To-Date Does Not Support Expanding Solicitations*, June 2019, *available at* https://ceadvisors.com/wp-content/uploads/2019/06/CEA_Order1000report_final.pdf ("Concentric 2019").

[4] This is not the first time that the availability of better data has been acknowledged or that such data has been reviewed. *See, e.g.*, Concentric Energy Advisors, Inc., *Competitive Transmission: Experience to-Date Shows Order No. 1000 Solicitations Fail to Show Benefits*, August 2022, *available at* https://ceadvisors.com/publication/competitive-transmission-experience-to-date-shows-order-no-1000-

This whitepaper aims to revisit the analysis of the 2019 Report with the benefit of new information. First, it repeats the core analysis of the 2019 Report but substitutes final project cost data – or more recent estimates where appropriate – for the estimated project cost data available in 2019. In the first instance, this is done with as little modification as possible. Second, the whitepaper introduces several analytic "scenario" results that reflect limited, but reasonable, adjustments to the data along with calculations and discussion. Third, with now-available project cost information, the whitepaper compares updated project costs to the same projects' winning bid amounts and to cost caps associated with winning bids.[5]

To provide consistency and simplicity of reporting, this whitepaper uses the 2019 Report's Baselines without judging whether the Baselines are appropriate and notwithstanding previously identified shortcomings. This whitepaper attempts to assess what the same approach would tell us now, with the benefit of new information, and for that reason does not endeavor to put forward a new methodology.[6]

All of the calculations used in the analysis presented in this whitepaper are simple, repeatable, and do not require processing of large data sets or special expertise. All data is public and thoroughly sourced (see Appendix 3). And, in the end, the results of the analysis are clear.

II. Updating the Analysis of the 2019 Report

The analysis presented in the 2019 Report was based on 22 discrete competitively bid projects in North America.[7] The first task is to revisit this list to focus on those projects for which more mature data is available and to purposefully exclude certain projects that are not instructive in terms of drawing conclusions about the cost savings benefits of Order No. 1000 competitive solicitations.

- Six projects were either cancelled, withdrawn, or placed on indefinite hold.[8] Projects that do not become used and useful will never have a final project cost and therefore do not yield savings relative to an alternative development pathway, so these projects are excluded.

solicitations-fail-to-show-benefits/ ("Concentric 2022"). This is, however, the first time that current cost data has been used to perform an updated, apples-to-apples comparison with the 2019 Report.

[5] We do not attempt to address the additional costs associated with administering the competitive solicitation processes, nor the cost of delay that is introduced by those processes. Further discussion of these issues can be found in other reporting. *See, e.g.*, Concentric 2019, pp. 25-32.

[6] Nothing in this whitepaper should be construed as minimizing other concerns raised about the 2019 Report or as validating the approach taken by the authors of that report – which tended to bias the results towards higher calculated savings from competitive solicitations.

[7] Numerous additional competitive solicitations were also identified in the PJM region, but, owing to the competitive framework in PJM, most such solicitations were not found to be relevant for the analysis by the authors of the 2019 Report.

[8] Cancelled or suspended projects included Gates-Gregg, the Imperial Valley Project, Liberal-Walkemeyer, and AP South (a.k.a. Transource Project 9A). Wheeler Ridge Junction is on indefinite hold. Hartburg-Sabine Junction was withdrawn.

- One project, Spring Substation, was re-scoped (i.e., larger and more expensive) to such a degree that it is not reasonable to compare prior project cost estimates to current cost estimates.[9]
- Three projects, NYISO Public Policy Segments A and B and Thorofare in PJM,[10] do not have available data that allow the establishment of a project cost estimate Baseline from which to calculate cost savings from the competitive solicitation in a manner consistent with the rest of the 2019 Report. This was true in 2019 and remains true now.
- Finally, the 2019 Report included three projects developed in Canada, which are also excluded as not being relevant to the issue of whether Order No. 1000 competitive solicitations deliver cost savings to customers.[11]

This leaves nine projects for which there is an opportunity to update the analysis underlying the 2019 Report and provide new insights about the purported cost savings benefits of Order No. 1000 solicitations.[12]

As to calculations, the cost savings math for each project requires comparison of a Baseline to a later cost. For the Baseline, the 2019 Report uses approaches that vary by region owing in part to challenges with the inconsistency of available data.[13] In some regions, the Report uses planning level cost estimates developed by the RTO/ISO and, in other regions, the Report uses the lowest incumbent bid cost.[14] Despite identified concerns with this methodology for setting Baselines,[15] we will nonetheless adopt the Baselines from the 2019 Report for this analysis.

[9] In the CAISO 2017-2018 transmission planning process, the Spring Substation project, which had been approved in 2014 and originally competitively awarded to PG&E at an estimated cost of $35-45M, was rescoped and expanded. The new project is called the "Morgan Hill Area Reinforcement" with an estimated cost (in 2017-2018) of $72-104M. *See* http://www.caiso.com/Documents/BoardApproved-2017-2018_Transmission_Plan.pdf, pp. 125 -126. As of more recent reporting, the project is slated for completion in Q3 2027 (*see* https://www.caiso.com/InitiativeDocuments/ISO-Board-Approved-2022-2023-Transmission-Plan.pdf) with an estimated cost of $135M (*see* https://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=751644).

[10] Thorofare does not have a project Baseline as defined here, consistent with how the data is presented in the 2019 Report. The lack of Baseline leads to no calculated percentage savings or cost growth relative to a Baseline. However, note that Transource's winning bid for Thorofare was $60M and the final project cost was $82M, a cost growth of 37%.

[11] The data provided for these projects requires considerable discussion to understand but, more importantly, these projects are not subject to FERC-jurisdictional rates and oversight (nor any other related US federal or state regulatory authority), and were not developed through Commission-approved and compliant transmission planning processes. They are thus poor analogs and will be excluded here.

[12] The nine projects are: Sycamore-Peñasquitos, Delaney-Colorado River (a.k.a. Ten West Link), Estrella Substation, Suncrest Reactive Power Support, Harry Allen-Eldorado, Miguel Reactive Power Support, Duff-Coleman, Western NY Public Policy Transmission (a.k.a. Empire State), and Artificial Island.

[13] *See* 2019 Report, p. 26.

[14] This is described in the 2019 Report, Figure 19.

[15] Critiques of the validity of the approach for setting Baselines in the 2019 Report, including challenges with relying on planning-level cost estimates, are discussed extensively in the Concentric 2019 Report. *See* Concentric 2019, pp. 18-24.

To calculate cost savings, later project cost data were compared to project-specific Baselines. The 2019 Report used then-current project cost estimates for each project. Here, we *replace* these figures with the most up-to-date project costs – this is the critical element that distinguishes the analysis in this whitepaper. In most cases, the projects are complete and final project costs are known.[16] Calculations to assess savings, or lack thereof, between the updated cost and the Baseline are simple and are unchanged between the analysis presented here and the calculations done in the 2019 Report.[17]

Figure 2 shows the data used in the 2019 Report and the calculation by the 2019 Report authors of the expected savings from Order No. 1000 competitive solicitations. Using the figures shown, the 2019 Report methodology would have identified an average expected cost savings of approximately 34%. After incorporation of certain escalation factors by the authors of the 2019 Report, and in part because of using a longer project list, this calculation was used to draw the conclusion that cost savings from competitive solicitations of 20-30% can be expected.

Figure 2: 2019 Report Data and Savings Calculations[18]

	Cost Baseline from 2019 Report ($M) [A]	Cost Estimate Used in 2019 Report ($M) [B]	2019 Cost Estimate vs. Baseline [C] = [B]/[A]-1
Sycamore-Peñasquitos*	$221	$108	-51%
Ten West Link / DCRT	$300	$280	-7%
Estrella	$45	$20	-56%
Suncrest	$75	$37	-50%
Harry Allen-Eldorado	$144	$133	-8%
Miguel*	$40	n/a	n/a
Duff-Coleman	$59	$50	-15%
Empire State	$232	$181	-22%
Artificial Island	$692	$273	-61%
Average			**-34%**

* *Projects developed by incumbent transmission owner (SDG&E).*

[16] The Estrella Substation project is considerably delayed but updated cost estimates are available, so we rely on those and update the current project cost estimate. The Ten West Link Project is in an adequately advanced stage of construction that near-final costs are known.

[17] We exclude any cost escalations calculations of the type used in the 2019 Report as they are unnecessary when final / near-final costs are available. Also, for simplicity, we opted not to factor in inflation adjustments for any project cost figures. Making all dollar amounts equivalent in terms of vintage can be controversial and adds complexity to the analysis. In some instances, as in the case of the Harry Allen-Eldorado project, inflation adjustments have already been incorporated in the underlying sources. In other instances, we expect that inflation has been accounted for in competitive processes and bids. While the exclusion of inflation adjustments in some cases may skew results, we expect these impacts to be moderate and not significant enough to alter the overall conclusions presented in this whitepaper.

[18] All data in this figure is directly from the 2019 Report, Table 6, with the exception of the average figure, which is calculated from the values in column [C]. The data in column [A] was a particular area of critique

Figure 3 shows the calculation of actual savings using the updated, mature cost data relative to the same Baselines employed in the 2019 Report. Overall, the calculated savings from Order No. 1000 solicitations vanish. The availability of final project costs demonstrates that, for the Order No. 1000 competitive projects reviewed, project costs average 6% *higher* than the Baseline. While certain projects exhibit savings relative to the Baseline, two-thirds of the projects reviewed have been completed with final project costs significantly higher than reference cost represented by the Baseline.

Figure 3: Updated Competitive Project Cost Data and Savings Calculations

	Cost Baseline from 2019 Report ($M)[19] [A]	**Current Cost as of 2023 ($M)[20] [B]**	**2023 Cost Data vs. Baseline [C] = [B]/[A]-1**
Sycamore-Peñasquitos	$221	$225	2%
Ten West Link / DCRT	$300	$389*	30%
Estrella	$45	$55	22%
Suncrest	$75	$53	-29%
Harry Allen-Eldorado	$144	$204	42%
Miguel	$40	$58	45%
Duff-Coleman	$59	$54	-8%
Empire State	$232	$264	14%
Artificial Island[21]	$692*	$273	-61%
Average			**+6%**

* *These two figures are particularly impactful to the analytic result as well as being the subject of controversy or uncertainty. They are addressed in more detail in Section III of this whitepaper.*

III. Considering Limited, Reasonable Modifications to the Updated Analysis

The above analysis accepts, for the purposes of argument, the Baselines amounts and the approach for defining Baselines that was used in the 2019 Report. While this approach suffers from shortcomings, it is particularly distorting in the case of the Artificial Island project. The Artificial Island solicitation has a complicated history that spanned several years and multiple

in 2019 for several reasons, one of which was that, in many cases, RTO/ISO planning level cost estimates were presented as ranges and the 2019 Report selected the high end of the range as a Baseline, which would tend to bias the calculated savings results higher. For example, for the Sycamore-Peñasquitos line, CAISO had an estimated cost range of $111-221M owing to the fact that the project could be AC or DC, overhead or underground, or a combination. *See, e.g.,* Sycamore-Peñasquitos Project Sponsor Selection Report*, at p. 2 (Mar. 4, 2014), available at* https://www.caiso.com/Documents/Sycamore-PenasquitosProjectSponsorSelectionReport.pdf.

[19] Data in this column [A] is unchanged from Figure 2 and sourced directly from the 2019 Report, Table 6.

[20] Data in this column [B] is what is introduced for this analysis and details regarding the sources can be found in Appendix 3.

[21] For this figure (Figure 3) and the figure above (Figure 2), Artificial Island costs include both non-incumbent and incumbent costs, consistent with its presentation in the 2019 Report.

rounds of bid submission.[22] Between the submission of initial rounds of bids and the round of bidding that ultimately determined the winner (LS Power), many things changed, most significantly the scope of the solicitation.[23] The 2019 Report notes that the lowest bid ultimately offered by an incumbent (PSEG) was $285M. To achieve an apples-to-apples comparison of final project cost to a Baseline defined as the lowest bid by an incumbent, the $285M figure is the appropriate one to use, not the $692M figure used in the 2019 Report, which was based on a bid by PSEG *before* the project scope changed leading to subsequent, lower cost bids. Substituting this more-appropriate $285M cost as the Baseline for Artificial Island leads to a calculated project-specific cost savings of 4%, rather than the 61% savings calculated in the 2019 Report.[24]

The other reasonable modification included in our analysis relates to the assumed final recoverable cost of Ten West Link. As a conservative assumption, the analysis above assumes that DCR Transmission ("DCRT") – developer of the Ten West Link project – is only allowed cost recovery up to the cost level approved by the California Public Utilities Commission in the associated Certificate of Public Convenience and Necessity ("CPCN") process, or $389M. However, DCRT has sought approval from the Commission for recovery of $553M, the actual project cost.[25] While the result of DCRT's cost recovery docket is pending, by setting the issue for settlement discussions the Commission has created the possibility that DCRT will be allowed to recover more than the $389M. Substituting the full requested $553M project cost as the final project capital cost for Ten West Link leads to a calculated project-specific cost increase of 84%, rather than the 7% cost savings calculated in the 2019 Report.

Considering the two modifications described above – using a more appropriate Baseline for Artificial Island and assuming that DCRT is allowed to recover its full project costs – the combined impact on total realized savings, or costs in excess of Baselines, on competitive transmission projects are as follows:

- Using a more appropriate Baseline for Artificial Island, the average competitive transmission project is 12% more expensive than Baselines.
- Assuming that DCRT is allowed to recover its full capital costs for Ten West Link, the average competitive transmission project is 12% more expensive than Baselines.

---

[22] While Artificial Island was a competitively bid project under PJM's Tariff, it was not solicited pursuant to Order No. 1000 competitive processes but is included here to avoid any potential criticism of eliminating a project with purported cost savings.

[23] The authors of the 2019 Report acknowledge as much (2019 Report, p. 32 (describing history of Artificial Island solicitation)) and the challenges with the solicitation process are further described in Concentric 2019 at page 21.

[24] Figures used here for the Artificial Island project include elements of the project developed by both the non-incumbent (LS Power Silver Run) and incumbent transmission (PSEG) owners.

[25] *See DCR Transmission, L.L.C.*, 184 FERC ¶ 61,199 (Sept. 29, 2023) (setting transmission tariff and revenue requirement filing for hearing and settlement judge procedures).

- Using a more appropriate Baseline for Artificial Island *and* assuming that DCRT is allowed to recover its full capital costs for Ten West Link, the average competitive transmission project is 19% more expensive than Baselines.

The tables supporting the above calculations can be found in Appendix 2. Taken together, incorporating more appropriate dollar amounts for certain key calculation inputs leads to outcomes that indicate Order No. 1000 competitively developed projects tend to exceed the posited Baseline amounts by an even greater degree.

It is worth acknowledging that these calculations are performed on an unweighted basis, whereby the average savings are calculated based on the simple average of the percent savings or exceedance experienced by each project. This approach is consistent with the methodology of the 2019 Report. However, the result holds if the calculation is done on a weighted basis – by adding together all of the Baselines and comparing them to the sum of all updated project costs. With the adjustments described above for the Artificial Island and Ten West Link projects, a "weighted" calculation would indicate the aggregate updated project costs exceed the aggregate Baselines by 24%.

IV. Applying Updated Cost Data to Observations About Winning Bids from Competitive Solicitations

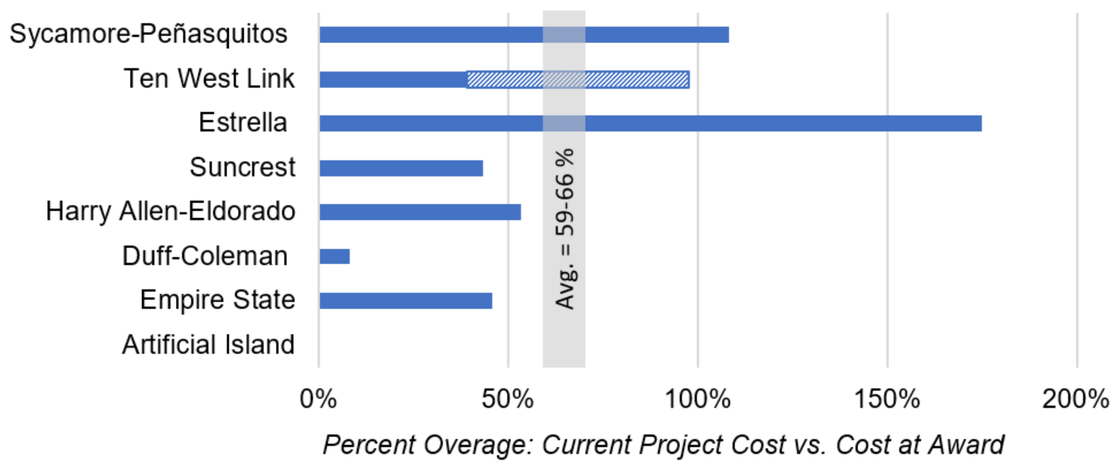
For Order No. 1000 solicitations to reliably select the more efficient and cost-effective transmission project from among numerous proposals, it is important for solicitation administrators to have an accurate indication of what projects are expected to cost. This analytic exercise offers an opportunity to review whether final recoverable project costs for projects resulting from Order No. 1000 solicitations reflect cost expectations expressed by bidders at the time of the solicitation. There is good evidence they do not. As Figure 4 shows, of the competitive projects listed in the 2019 Report that are being analyzed here, most projects have (or are expected to have) final recoverable costs that considerably exceed the project cost of the winning bid at the time of the award.[26] Indeed, of the eight projects analyzed,[27] the average final recoverable cost exceeds the winning bid amount by 59-66% on average.

[26] This is consistent with observations made by Dr. Carl Peterson in his 2022 Affidavit, in which he pointed out that competitive solicitations can create incentives to offer strategically to win the contract to develop a project, but such winning bids then give way to considerable risks of *ex post* opportunism associated with contract execution that lessen the value of the competitive procurement and the relevance of the winning bid. That is, bidders will offer to win, after which there are considerable challenges to constraining ultimate project costs, even where there are cost caps in place. *See* Reply Comments of Developers Advocating Transmission Advancements, FERC Docket No. RM21-17-000 (Sept. 19, 2022) (attaching Affidavit of Dr. Carl Peterson).

[27] The Miguel project is excluded from this analysis because there was no project cost associated with the winning bid. SDG&E was awarded the project as the only bidder.

Figure 4: Winning Bid Project Cost Compared to Updated Project Costs

	Cost of Selected Proposal[28] ($M)	Current Cost as of 2023 ($M)	Current Cost in Excess of Cost at Award (%)
Sycamore-Peñasquitos	$108	$225	108%
Ten West Link / DCRT	$280	$389-553	39-98%
Estrella	$20	$55	175%
Suncrest	$37	$53	43%
Harry Allen-Eldorado	$133	$204	53%
Duff-Coleman	$50	$54	8%
Empire State	$181	$264	46%
Artificial Island	$273	$273	0%
Average			**59-66%**



V. Applying Updated Cost Data to Observations About Bidding Cost Caps

With the now-available project cost data, it is also worth considering what new can be learned about how final recoverable project costs compare to the cost caps included in winning bids. The issue of whether cost caps are meaningfully binding on winning bidders, and whether they ultimately provide cost containing and risk reducing benefits to customers, has been a matter of dispute, despite certain entities touting their virtues. In 2022, a Concentric report touched on the fact that cost cap exceptions were frequently being used to pass on cost increases to customers despite winning solicitations based on low bids.[29]

[28] All data in this figure is directly from the 2019 Report, Table 6. For Artificial Island, the 2019 Report identifies a range for the cost of the selected proposal of $263-283M, of which we use the midpoint for the sake of simplicity.

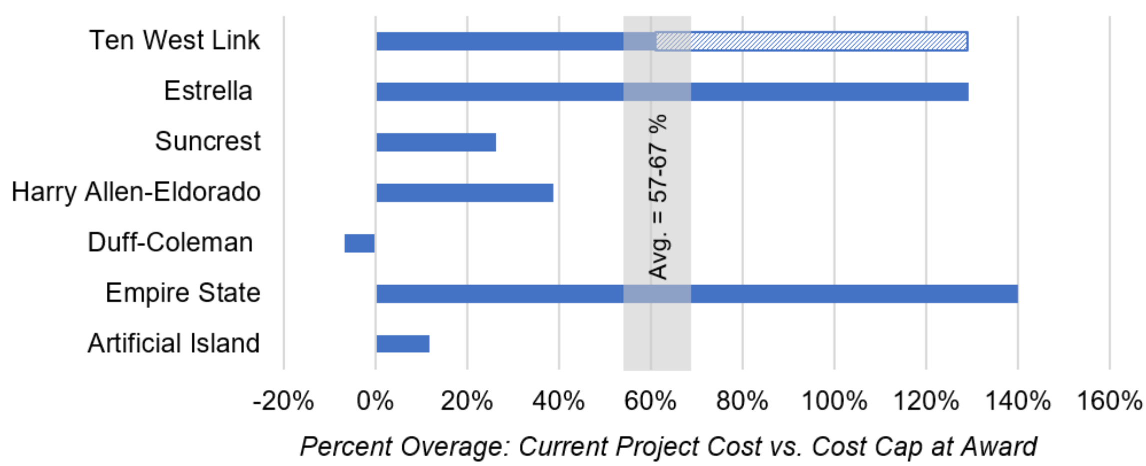
[29] Concentric 2022, p. 34.

As Figure 5 illustrates, of the seven competitive projects listed in the 2019 Report that are analyzed in this whitepaper and have cost caps in effect, only one project has been completed – or is expected to be completed – within the stated value of the cost cap. Many projects have final *recoverable* project costs that considerably exceed the dollar amount of the cost caps that were presented in the solicitation processes and touted in award announcements, with average final recoverable costs that are 57-67% higher than presented cost cap levels. Thus, regardless of the various reasons that project costs may increase above bid and cost capped levels, it appears that cost caps have failed to lead developers to contain project costs.

Figure 5: Winning Bid Cost Caps Levels Compared to Updated Project Costs

	Cost Cap at Time of Award ($M)	Current Cost as of 2023 ($M)	Current Cost in Excess of Cost Cap at Award (%)
Ten West Link / DCRT	$242	$389-553	61-129%
Estrella[30]	$24	$55	129%
Suncrest	$42	$53	26%
Harry Allen-Eldorado	$147	$204	39%
Duff-Coleman	$58	$54	-7%
Empire State	$110*	$264	140%
Artificial Island[31]	$146	$163	12%
Average			**57-67%**

* *Negotiated in a post-award settlement before FERC.*



[30] As noted prior, the Estrella substation project is still at the permitting stage. All other projects are complete or, as in the case of Ten West Link, near final project costs numbers are available.

[31] This figure includes only portion of project won by LS Power Silver Run (not those completed by DPL or PSEG) for the sake of comparing cost performance relative to LS Power's proposed cost cap level.

VI. Conclusion

The simple analysis presented in this whitepaper offers the opportunity to update insights into the outcomes of competitive solicitations for transmission projects under Order No. 1000. Revisiting the analysis presented by The Brattle Group in the 2019 Report with mature project cost data, updated calculations do not show cost savings. Rather, an updated analysis shows that competitively developed projects on average have exceeded cost Baselines by 6%. With certain limited adjustments that are reasonable and appropriate, average recoverable costs exceed Baselines by 12-19%.

Furthermore, review of bid and cost data for the same projects reveals (1) that competitively developed transmission projects exceed cost expectations at the time of award by 59-66% on average, and (2) that competitively developed transmission projects with cost caps in winning bids have exceeded those cost cap amounts by 57-67%. These analyses contradict prior conclusions that Order No. 1000 solicitations yield cost savings for customers, and that cost caps resulting from competitive solicitations provide meaningful cost containment protections for customers.

Note that this analysis is not intended to support the assertion that projects developed by non-incumbents or with cost caps (or other cost control measures) are more, or less, subject to issues that arise when building transmission. Transmission project development is fundamentally a challenging endeavor and projects developed by incumbents also face cost and schedule variance.[32] Indeed, two of the projects included in this analysis update were built by an incumbent developer (Sycamore-Peñasquitos and Miguel). However, the critical insight is that assertions about the cost saving benefits of Order No. 1000 competition are not, in the final accounting, supported by current evidence.

[32] To this point, prior analysis 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.” (Concentric 2019, p. iii.)

Appendix 1: List of Projects from 2019 Report

Figure 6: Source 2019 Report, Figure 10

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

Appendix 2: Data Tables for Scenarios

Figure 7: Updated Competitive Project Cost Data and Savings Calculations with Modifications to only Artificial Island Baseline (adjusted fields in bold & italic)

	Project Cost Baseline ($M) [A]	Current Cost as of 2023 ($M) [B]	2023 Cost Data vs. Baseline [C] = [B]/[A]-1
Sycamore-Peñasquitos	$221	$225	2%
Ten West Link / DCRT	$300	$389	30%
Estrella	$45	$55	22%
Suncrest	$75	$53	-29%
Harry Allen-Eldorado	$144	$204	42%
Miguel	$40	$58	45%
Duff-Coleman	$59	$54	-8%
Empire State	$232	$264	14%
Artificial Island	***$285***	$273	***-4%***
Average			**+12%**

Figure 8: Updated Competitive Project Cost Data and Savings Calculations with Modifications to only Ten West Link Allowed Recovery (adjusted fields in bold & italic)

	Project Cost Baseline ($M) [A]	Current Cost as of 2023 ($M) [B]	2023 Cost Data vs. Baseline [C] = [B]/[A]-1
Sycamore-Peñasquitos	$221	$225	2%
Ten West Link / DCRT	$300	***$553***	***84%***
Estrella	$45	$55	22%
Suncrest	$75	$53	-29%
Harry Allen-Eldorado	$144	$204	42%
Miguel	$40	$58	45%
Duff-Coleman	$59	$54	-8%
Empire State	$232	$264	14%
Artificial Island	$692	$273	-61%
Average			**+12%**

Figure 9: Updated Competitive Project Cost Data and Savings Calculations with Modifications to Artificial Island Baseline and Ten West Link Allowed Recovery (adjusted fields in bold & italic)

	Project Cost Baseline ($M) [A]	**Current Cost as of 2023 ($M) [B]**	**2023 Cost Data vs. Baseline [C] = [B]/[A]-1**
Sycamore-Peñasquitos	$221	$225	2%
Ten West Link / DCRT	$300	***$553***	***84%***
Estrella	$45	$55	22%
Suncrest	$75	$53	-29%
Harry Allen-Eldorado	$144	$204	42%
Miguel	$40	$58	45%
Duff-Coleman	$59	$54	-8%
Empire State	$232	$264	14%
Artificial Island	***$285***	$273	***-4%***
Average			**+19%**

Appendix 3: Data References

Project	Data Category	Cost	Reference and Notes
Sycamore-Peñasquitos	Final Project Cost	$225M	Fifth Transmission Owner Formula Rate Tariff filing, FERC Docket No. ER19-221, Worksheet on Forecast of Transmission Capital Additions (October 30, 2018). Note that this project went into service September 2018 and is frequently referred to as "SX-PQ" in SDG&E documentation.
DCR / Ten West Link	CPCN Approved Cost	$389M	DCRT Rate recovery application Transmittal Letter, FERC Docket No. ER23-2309, p. 19 (June 29, 2023).
DCR / Ten West Link	Requested Recovery Amount	$553M	DCRT Rate recovery application Transmittal Letter, FERC Docket No. ER23-2309, p. 18 (June 29, 2023).
DCR / Ten West Link	Cost Cap	$242M	DCRT Rate recovery application Transmittal Letter, FERC Docket No. ER23-2309, p. 17 (June 29, 2023). At a later point in the development process, Ten West Link underwent a route change and faced numerous regulatory delays. It then negotiated a second amended cost cap with CAISO of $258,961,024 *See* Motion to Intervene and Comments of the California Independent System Operator Corporation, FERC Docket No. ER23-2309, p. 1 (July 21, 2023). For consistency, this whitepaper is using initial cost caps as those are what are frequently referenced in public claims related to how competition provides cost saving benefits to customers.
Estrella	Cost Cap	$24M	Motion to Intervene and Comments of the CAISO, FERC Docket No. ER15-2239, p.4 (Aug. 12, 2015).
Estrella	Current Project Cost Estimate	$55M	2022-2023 Transmission Plan High Voltage Transmission Access Charge Capital Costs (*available at* http://www.caiso.com/Documents/2022-2023TransmissionAccessCharge-HighVoltageCapitalCostEstimates.xlsx).
Suncrest	Cost Cap	$42M	Motion to Intervene and Comments of the CAISO, FERC Docket No. ER15-2239, p.4 (Aug. 12, 2015).
Suncrest	Final Project Cost	$53M	Horizon West Annual Actual 2021 transmission plant in service, gross transmission plant in service, p. 2 (*available at* https://www.horizonwesttransmission.com/regulatory.html).

Project	Data Category	Cost	Reference and Notes
			In its 2023 formula rate filings, Horizon West – a company that has only Suncrest as an in-service project – reports a total gross plant of $73M and an unamortized regulatory asset of $12M. It is unclear what has led to the increase in plant in service or the details of the regulatory asset. For the purpose of this analysis, we use the gross plant in service from Horizon West's 2021 formula rate filings because of the uncertainty about what has driven this considerable change in gross plant in service, though it is noteworthy that a considerably larger amount that the $53M is being included in rate base and recovered from customers.
Harry Allen-Eldorado	Cost Cap	$147M	Harry Allen-Eldorado 500 kV Transmission Line Project, Project Sponsor Selection Report, p. 73 (Jan. 11, 2016) (*available at* https://desertlinktransmission.com/wp-content/uploads/2020/12/CAISO-Selection-Report.pdf) This quantity was agreed to in 2020 dollars.
Harry Allen-Eldorado	Final Project Cost	$204M	DesertLink 2022 Annual Formula Rate Update, for the 12 months ended 12/31/2022 (available at https://desertlinktransmission.com/wp-content/uploads/2023/06/20230630_DesertLink_2022_Annual_Update.pdf) Note that, since this project was placed in service, the gross plant in service figures have increased in Desert Link's formula rate filings. For this figure, we use the gross plant in-service figure from the 2022 update as the indicator of what customers are compensating the developer for as the rate-based value of the project.
Miguel Reactive Power	Final Project Cost	$58M	San Diego Gas & Electric Company, Volume 2, TO4 – Cycle 5, Base Period and True-Up Period Work Papers; HV-LV Plant Allocation Study; Forecast Period Capital Additions Work Papers; and Sunrise Expense, Summary (Nov. 30, 2017) (*available at* https://www.sdge.com/sites/default/files/Volume%202%20-%20TO4%20C5%20WPs.pdf)
Duff-Coleman	Cost Cap	$58M	2019 Report, p. 41 Second Amended and Restated Selected Developer Agreement between Republic Transmission and MISO, Nov. 15, 2019. *See also Republic Transmission, LLC*, 167 FERC ¶ 61,215, at P 4 (2019).
Duff-Coleman	Final Project Cost	$54M	MISO Regionally Cost Shared Project Reporting Analysis, Quarterly Status Report, Complete as of June 11, 2020, 2020 Duff-Coleman EHV Quarterly Reports.zip file (May 18, 2023).

Project	Data Category	Cost	Reference and Notes
Empire State	Final Project Cost	$264M	Annual Informational Filing, Exhibit A, Total Gross Plant, FERC Docket No. ER23-1381 (Mar. 15, 2023). Note that the gross plant in service figures have increased since the Empire State Line was placed in service June 1, 2022. For this figure, we use the gross plant in-service figure from the 2023 Forecast because it is the indicator of what customers are compensating the developer for as the rate-based value of the project.
Empire State	Capped Cost Amount	$110M	NextEra Energy Transmission New York, Inc. 2021 & 2022 Formula Rate Annual Projection Response to the New York Transmission Owners' Questions Provided on 12/1/2021, p. 3. FERC Settlement Agreement, FERC Docket No. ER16-2719-000, and Next Energy Transmission New York, Inc. "2021 & 2022 Formula Rate Annual Projection Response to the New York Transmission Owners' Questions Provided on 12/1/2021" January 10, 2022, p 3 (*available at* https://www.nyiso.com/documents/20142/27732105/NEETNY-2021-2022AnnlPrjctn-RspnsNYTODataRqst.pdf/553f58f1-f54f-2519-28d7-bd058cb9e3a0)
Artificial Island	Lowest Incumbent Bid	$285M	See 2019 Report, p. 32. *See also* Artificial Island Project Recommendation White Paper, PJM, p. 33 (Jul. 29, 2015) *(available at* https://www.pjm.com/~/media/committees-groups/committees/teac/postings/artificial-island-project-recommendation.ashx) Note that the 2019 Report lists the PS&G bid, the lowest incumbent bid for the second round of the Artificial Island solicitation, as $285M. However, the Artificial Island Whitepaper Recommendation lists the cost for the PS&G bid as "$277-$285[M]".
Artificial Island	Cost Cap for LS Power	$146M	Artificial Island Designated Entity Agreement, Schedule E, Section 1.2(b), FERC Docket No. ER19-1981-000 (filed May 24, 2019). This cost cap for the LS Power portion of the project included allowances for inflation and at the time of the project in-service date LS Power sates that the updated cost cap would be $166.3M. For the purposes of this Whitepaper, the focus is on the amount of the cost cap at the time of the award, so the initial stated amount is used. *See, e.g.,* 2020 Annual Update (True-up) Stakeholder Meeting (*available at* https://www.silverrunelectric.com/wp-content/uploads/2021/08/20210813_Silver_Run_2020_True-Up_Meeting_Presentation.pdf)

Project	Data Category	Cost	Reference and Notes
Artificial Island	LS Power Portion of Project Cost	$163M	Silver Run 2023 Projection, revised, Attachment 4 (*available at* https://www.silverrunelectric.com/wp-content/uploads/2022/11/20221130_Silver_Run_2023_Projection_revised.pdf) Note that the costs of the LS Power portion of the Silver Run project have increased since the project went into service in May 2020. For this figure, we use the gross plant in-service from the 2023 formula rate projection because it is the indicator of what customers are compensating the developer for as the rate-based value of the project.
Artificial Island	PSEG & DPL Portions of Project Cost	$110M	PJM Transmission Cost Information Center ("TCIC") entries for Artificial Island: b2633 (b2633.10, b2633.4, b2366.5) (*available at* https://www.pjm.com/planning/project-construction)
Artificial Island	Total Project Cost	$273M	PSEG & DPL Portions of Capital Cost (above) *plus* LS Power Potion of Capital Cost (above)
Thorofare	Final Project Cost	$82M	PJM TCIC for Thorofare: b2609 Informational Filing of Annual True-up Adjustment to 2020 Projected Transmission Revenue Requirement of Transource West Virginia, LLC, Appendix A, FERC Docket No. ER15-2114 (June 30, 2021).

Document Content(s)