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Chair David Olsen
Governor Ashutosh Bhagwat
Governor Mark Ferron
Governor Angelina Galiteva
Governor Richard Maullin

Mar 16, 2018

California Independent System Operator
250 Outcropping Way
Folsom, California

Re: Economic Studies for CAISO Transmission Planning Process

Dear Chairman Olsen and Governors,

LS Power would like to commend CAISO staff for the good work done under the 2017/18 Transmission Plan. CAISO not only performed Reliability, Economic and Policy-Driven assessments but also took on several Special Studies, such as Interregional Transmission Project evaluation and 50% RPS Out-of-State Portfolio Assessment, Risk of early economic retirement of gas fleet, Benefits of Large Energy Storage, Frequency response assessment, Gas/Electric coordination, and Slow response Local Capacity resources. All these were key topics of interest to stakeholders and provided valuable insights. LS Power supports CAISO Management's recommendation of approval of the 2017/18 Transmission Plan by the CAISO Board.

One area where improvements should be made in the transmission planning process going forward is to implement modelling enhancements to properly capture intertie congestion, particularly along the California Oregon Intertie (COI). We recommend that CAISO staff take this as a high priority task under the 2018/19 Transmission Plan. Failing to capture this congestion issue in planning studies leads to years of inaction. Ultimately, COI congestion has cost CAISO ratepayers between $50 to $147 mm every year since 2011[1]. The question at hand is whether CAISO ratepayers should continue to pay for this congestion or would this money be better spent in building new transmission infrastructure that pays for itself by reducing congestion costs while providing grid reliability and diversity benefits.

[1] As per 2013 & 2016 CAISO DMM Annual Reports on Market Issues & Performance, Section 8, Table 8.1, PACI & NOB congestion combined was approximately $75mm in 2016, $50 mm in 2015, $147mm in 2014, $62mm in 2013, $144mm in 2012, $74mm in 2011.
http://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf
http://www.caiso.com/Documents/2013AnnualReport-MarketIssue-Performance.pdf

PACI, NOB & COI Congestion:

For the past three planning cycles, LS Power has registered its concern that CAISO's economic studies performed for the Transmission Planning Process (TPP) consistently fail to capture the tens to hundreds of million dollars in annual congestion costs that show up along the Pacific AC Intertie (PACI), which is a portion of the COI, and the Nevada/Oregon Border (NOB) interface which is adjacent to COI, and therefore consistently fail to identify economic benefits related to transmission solutions submitted in the annual TPP process. Since 2011, actual PACI and NOB congestion per CAISO DMM reports has been in the range of $50 mm to $147 mm per year. This contrasts with the less than $1mm of annual congestion predicted in CAISO planning studies for the COI path[2.] In the past CAISO stated its belief that congestion on the PACI interface was temporary, caused by transmission outages during the 2012/13 timeframe, and would be mostly mitigated by completion of the transmission outage work. However, since completion of the outage work, significant congestion still routinely gets recorded. Another reason given for not enhancing the transmission planning model to more accurately capture congestion was the belief that the solar generation built to satisfy the 33% RPS in California would reduce the North to South direction flows on COI, thereby lowering congestion costs. This however seems to not be the case as 10,000 MW of renewables has since been added to the grid but the significant congestion cost on this intertie persists. CAISO staff has made minor adjustments to enhance its planning models in last two planning cycles as an attempt to capture more of this congestion and, while these enhancements have helped improve congestion modelling, the transmission planning model is still not close to capturing the congestion witnessed in the Day Ahead market and detailed in the DMM annual reports.

It is estimated that the Southwest Intertie North (SWIP-North) project, which LS Power has submitted in the past three TPP cycles, reduces COI flows by ~300 MW or more, based on the WECC Path Rating study work conducted by LS Power. Further, based on CAISO's analysis done under the Transmission Planning Process, CAISO found that SWIP-North reduces congestion hours on COI by 39%. Given that insignificant congestion gets quantified in CAISO studies, the congestion relief and related economic savings offered by projects such as SWIP-North continue to be lost as do the benefits of increasing capacity between California and the Pacific Northwest. Resolving the discrepancy between real world congestion vs the congestion predicted through studies is even more important now given the February 15, 2018 letter[3] from CEC and CPUC requesting that the CAISO do a special sensitivity study in its current 2018/19 TPP that looks at increasing the transfer of low-carbon supplies to California from the Pacific Northwest. The efforts on this study will be well served if CAISO first properly captures the

[2] California Oregon Intertie (COI) comprises of three transmission lines that have a combined flow limit of 4800 MW N-S. CAISO TPP studies enforce this flow limit and capture any congestion on this path. In the Day Ahead scheduling world, congestion is witnessed across the Pacific AC Intertie (PACI) and Nevada/Oregon Border (NOB) scheduling interfaces. PACI is a subset of COI and has a scheduling limit of 3200 MW which represents scheduling rights of CAISO member entities on COI path. NOB is the scheduling interface for Pacific DC Intertie. It is rated at 3220 MW N-S and the transmission capacity is allocated between CAISO member entities and LADWP. NOB and COI are two parallel intertie paths that connect CAISO to Pacific Northwest.

[3] http://www.caiso.com/Documents/CPUCandCECLettertoISO-Feb152018.pdf

economic congestion that takes place on the PACI/NOB interfaces today and looks for options to alleviate this congestion. Benefits of projects such as SWIP-North, that not only help improve transfer capability but also provide reliability and policy benefits, can only be properly evaluated if this congestion is accurately modelled in the study.

Economic Model Enhancements recommended for 2018/19 TPP:

In order to understand the discrepancies between congestion quantified by CAISO planning studies and real world congestion as shown in CAISO DMM reports, LS Power contracted with The Brattle Group (Brattle) to conduct an economic study to capture PACI & NOB congestion. Brattle's findings[4] were submitted to CAISO as part of comments filed by LS Power in Oct 2017 for 2017/18 TPP. Brattle's work is attached to this letter and a brief summary of Brattle's recommendations was sent again to CAISO in response to comments recently filed by LS Power[5] for 2018/19 TPP (also attached). Brattle made several recommendations that if implemented should help accurately quantify intertie congestion. In addition, Brattle also concluded that the increasing magnitude of California's installed solar capacity is not a major driver in terms of reducing intertie congestion on paths such as PACI and NOB since this congestion typically occurs during periods of no/low solar output in California.

CAISO staff wasn't able to implement Brattle's recommended enhancements to its economic study models for 2017/18 TPP. We recommend these enhancements be implemented for the 2018/19 TPP study as a necessary first step to evaluate any potential increase in intertie capacity between California and the Pacific Northwest.

SWIP-North Transmission Project:

LS Power's attached comments to the 2018/19 TPP Study Plan included an economic study request for the SWIP-North transmission project. SWIP-North is comprised of a 500 kV transmission line from Midpoint substation in Idaho Power to Robinson Summit substation in NV Energy. Upon completion of SWIP-North, LS Power will, through its affiliates, own and control on a merchant basis (A) approximately 1000 MW of the capacity of the new SWIP-North line and (B) approximately 1000 MW of new[6] transmission capacity that will become available on the existing 500 kV transmission line that connects Robinson Summit to Harry Allen substation ("ON Line"), as per the Transmission Use and Capacity Exchange Agreement ("TUA") among LS Power affiliates and NV Energy. LS Power has proposed that this ~1000 MW

[4] LS Power comments (including Brattle findings) filed under 2017/18 TPP can be found at: http://www.caiso.com/Documents/LSPComments_2017-2018PreliminaryReliabilityResults.pdf

[5] LS Power comments for 2018/19 Draft Study Plan can be found at: http://www.caiso.com/Documents/LSPower-EconomicStudyRequest-Draft2018-2019StudyPlan.pdf

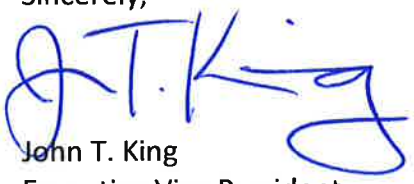
[6] The Robinson Summit to Harry Allen 500 kV line is currently limited to ~975 MW of transmission capacity. The completion of SWIP-North and its interconnection with ON Line will substantially increase the transmission capacity of ON Line. Approximately 1000 MW of that new ON Line capacity will be owned and controlled by an LS Power affiliate and could be dedicated for CAISO use.

capacity over SWIP-North and the new additional ~1000 MW capacity over ON Line be dedicated for CAISO use. In addition, the new 500 kV line from Harry Allen to Eldorado (HAE) was approved by CAISO to be in-service by 2020. Upon completion of the Harry Allen to Eldorado project, Harry Allen will be a CAISO delivery point. Hence, assuming SWIP-North is built for CAISO use, upon completion of the SWIP-North and HAE projects CAISO will control an uninterrupted 500 kV path (representing ~1000 MW of capacity) from Midpoint to Eldorado.

As CAISO performs a special sensitivity study under 2018/19 TPP to look at improving transfers from the Pacific Northwest, it should consider SWIP-North as a solution. SWIP-North can not only improve transfer capability between BPA and CAISO, but will also provide a new diverse transmission path with an additional 1000 MW transfer capability into/from California resulting in significant congestion relief and reliability and policy benefits to California. Benefits of SWIP-North were analyzed by Brattle in support of LS Power's submission of SWIP-North into the Interregional Planning process in May, 2016. This report is also attached here.

LS Power thanks the CAISO Board and Management for the opportunity to provide these comments and looks forward to working with CAISO staff as it conducts economic studies and the special sensitivity study to improve transfers to/from Pacific Northwest into California.

Sincerely,



John T. King
Executive Vice President
LS Power Development, LLC

cc:

Mr. Stephen Berberich, CEO, CAISO
Mr. Keith Casey, VP Market & Infrastructure Development, CAISO
Mr. Neil Millar, Executive Director, CAISO
Paul Thessen, President, LS Power
Mark Milburn, Vice President, LS Power
Sandeep Arora, Vice President, LS Power

Attachment A: LS Power comments to CAISO, Oct 2017 and Brattle recommendations

CAISO 2017/18 Transmission Planning Meeting Sep 21/22, 2017: Stakeholder Comments

Submitted by	Company	Date Submitted
Sandeep Arora (sarora@lspower.com) (925) 201 5252	LS Power Development, LLC	10/06/17

LS Power appreciates the opportunity to provide comments on the material presented at Sep 21, 22 meeting for CAISO's 2017/18 Transmission Plan. The following comments are related to the Economic Planning – Production Cost Model Development & Interregional Transmission project evaluation portions of CAISO's Sep 22, 2017 presentation.

Economic Planning – Production Cost Model Development:

Comments previously submitted by LS Power (at the Study Plan stage of the 2017/18 Transmission Plan[1] and Study Findings stage[2] of the 2016/17 Transmission Plan) noted certain deficiencies in CAISO's economic study models that result in significantly under-estimated Day Ahead Intertie Congestion on major CAISO Intertie paths. In particular, congestion on the Malin & Nevada-Oregon Border (NOB) paths has been reported in CAISO's Department of Market Monitoring (DMM) annual reports for the last four years in the range of $49 million to $149 million per year. In contrast, CAISO's economic studies as a part of the previous transmission plans show congestion costs on CAISO's California-Oregon Intertie (COI) and Pacific DC Intertie (PDCI) paths at less than $1 million per year. As previously noted in LS Power's comments, there are several reasons for this discrepancy -- but there are ways this discrepancy can be minimized if certain modelling enhancements are made to CAISO's economic study model. While CAISO has made some modelling enhancements in the 2016/17 TPP, there are several additional ones that still need to be made in order to more accurately capture intertie scheduling constraint congestion.

LS Power recently worked with The Brattle Group ("Brattle") to model some of the enhancements it had previously proposed to CAISO as an attempt to analyze their ability to represent actual

[1] LS Power comments on CAISO's Study Plan for 2017/18 TPP:
http://www.caiso.com/Documents/LSPower_EconomicStudyRequest_Draft2017-2018StudyPlan.pdf

[2] LS Power comments on CAISO's Economic Study presentation for 2016/17 TPP:
http://www.caiso.com/Documents/LSPowerComments_2016_2017TransmissionPlanningProcess_Nov16_2016Meeting.pdf

Intertie Congestion, especially on the Malin & NOB intertie scheduling constraints. A brief summary of this work is provided below and a Brattle slide deck report documenting this work is also being submitted along with these comments.

The Brattle Group Study – September 2017:

LS Power recently contracted with Brattle to conduct an economic planning study. The purpose of the study was to implement modeling enhancements to CAISO's 2016/17 production cost model and to perform production cost simulation studies to estimate the likely impact of these enhancements on congestion on the Malin & NOB intertie scheduling constraints.

Benchmarking the Study:

The Brattle work started from the CAISO's 2016/17 planning model database[3] which was used for the economic planning studies in the 2016/17 TPP cycle. The Brattle analysis converted that case from the native GridView data format for use in the Power System Optimizer (PSO), another commercially available production cost simulation model. PSO was used because it has the capability to simulate contract-path transactions and congestion on scheduling constraints, which apparently is not possible with the GridView model. The PSO simulation tool has been previously used for CAISO-sponsored studies, including the SB350 study.

As a first task, after converting the database to PSO, Brattle benchmarked this case against the CAISO's 2016/17 TPP economic planning study results. The outcomes of this benchmarking exercise are shown in the Brattle slide deck report which is being submitted with these comments. Although perfect benchmarking was not achieved, the amount of congestion noted using the PSO replication of the GridView case was lower than what was reported for a number of limiting constraints in CAISO's economic study. The differences relate to the fact that the models have different unit commitment algorithms (GridView uses a heuristic algorithm while PSO uses mixed-integer optimization) and how hurdle rates between balancing areas are imposed (GridView imposes hurdle rates on physical flows while PSO imposes hurdle rates on contract path transactions). However, the physical COI congestion in the Brattle benchmarking case was very close to what CAISO had identified in its TPP GridView case.

Modelling Enhancements:

After completing the benchmark simulation, Brattle analysis modelled the following enhancements: (a) added Intertie scheduling constraints to create a more accurate representation of WECC-wide scheduling and congestion, and (b) updated hurdle rates to better reflect the trading frictions that exist in bilateral scheduling, using assumptions from the SB350 study. In addition, Brattle simulations included a case with preliminary assumptions about existing contract paths and reduced hurdle rates for hydro resources from BC Hydro's system to

[3] Downloaded from CAISO's Market Participant Portal. This case is a 2026 system representation.

reflect the reality that PowerEx (a) likely has long-term transmission reservations to reach the CAISO's Malin and NOB scheduling points, and (b) faces very low CO_2 costs for at least a portion of its hydro imports into California based on its Asset Controlling Supplier emissions rate filed with the California Air Resources Board[4].

As a result of these enhancements, the simulated flows on Malin and NOB paths increased and were noted to be comparable to historical flows in some periods of similar net load and hydro conditions. The simulated 2026 power flows were lower than historical flows during the daytime hours due to the incremental solar generation that is projected to be online by 2026. However, the predicted flows and associated congestion on intertie scheduling constraints, such as Malin & NOB, remained high during the evening and night hours when solar generation is offline suggesting that solar buildout in California doesn't help reduce this congestion.

Study Findings:

The key findings of this modelling effort include:

(1) The simulation of intertie scheduling constraints shows ~$10 million in annual congestion on the Malin and NOB intertie scheduling constraints, which is over 10 times more congestion than what has been found in CAISO studies for COI and the PDCI for the last several TPP cycles but still lower than historical congestion.
(2) With the reduced PowerEx import hurdles, the simulated congestion on Malin and NOB increases to $14 million, or more than 15 times higher than in the 2016/17 TPP studies.
(3) The Brattle simulations show approximately 2,000-2,300 binding hours on Malin and NOB. While this result is still lower than the historical 2,800-4,700 hours, it is significantly greater than the 120 hours on COI and the PDCI predicted in the 2016/17 TPP.
(4) In addition to the Intertie scheduling congestion, the Brattle case also shows approximately $1 million in of physical congestion on COI, similar to what CAISO found.
(5) Additional modelling enhancements, as recommended in the Brattle slide deck report, should be implemented which will likely bring the congestion in Brattle simulations much closer to the historical $49 mm to $149 mm congestion.

Conclusion:

The Brattle study concluded that implementing select modelling enhancements that reflect contract path scheduling and intertie scheduling constraints significantly improves the realism of simulated congestion of these paths, partially resolving the large discrepancy between recorded historical congestion and congestion predicted by TPP studies. The study also showed that the increasing magnitude of California's installed solar capacity is not a major driver in terms of reducing ITC congestion on paths such as Malin & NOB since this congestion typically occurs during periods of no/low Solar output in California. Not all potential enhancements were

[4] Current and historical ACS rates for BPA, Powerex, and Tacoma Power are available at: https://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep-power/acs-power.htm

modelled in this Brattle study, but if they were, they would be expected to further reduce the discrepancy between simulated congestion in economic planning models and the actual congestion that is occurring in the CAISO market. The Brattle slide deck makes specific recommendations on what additional enhancements should be considered to simulate realistic levels of congestion on Malin & NOB.

Next Steps:

LS Power recommends that CAISO adopt these modeling enhancements for its 2017/18 TPP Economic Studies. Further, CAISO should simulate some sensitivities, such as various Hydro output assumptions for the Pacific Northwest and California, which can have substantial implications on power flows and disproportionately affect congestion over the Malin and NOB import paths, but were not explored in this study.

Interregional Transmission Project Evaluation:

LS Power has the following comments on this section of CAISO's presentation:

Robinson Summit to Harry Allen transmission capacity:

As part of its Interregional project submittal, LS Power had proposed that approximately 1000 MW of new transmission capacity will be dedicated for CAISO use after SWIP North project is built. This transmission capacity will be from Midpoint to Eldorado[5] 500 kV substations, approximately 575 miles. Pursuant to a Transmission Use and Capacity Exchange Agreement (TUA)[6] with NV Energy, once SWIP North is built there would be an exchange of capacity between Great Basin, a LS Power affiliate, and NV Energy. NV Energy would get a share of the capacity between Midpoint and Robinson Summit 500 kV and Great Basin would get a share of capacity between Robinson Summit and Harry Allen 500 kV (ON Line), without either party having to pay any amount for this capacity exchange to the other. As a result of this capacity exchange, LS Power would have bidirectional transmission capacity on the entire path from Midpoint to Harry Allen, estimated at approximately 1000 MW (subject to the terms of the TUA). This was recognized as a footnote in CAISO's presentation and we recommend that this assumption continue to be used for any future work to be done in this area. Given this, SWIP N project should not need to procure 1000 MW of transmission capacity between Robinson Summit & Harry Allen substation. Any additional transmission capacity on Robinson Summit to Harry Allen, as required to count WY wind resources as fully deliverable, can potentially be procured through NV Energy OATT.

Coal Shutdown can potentially create new Available Transmission Capacity on the existing system from WY to Midpoint:

As coal power plants east of Midpoint substation in Idaho retire, transmission capacity will likely

[5] The Harry Allen to Eldorado segment is on schedule to be in service in 2020.

[6] https://elibrary.ferc.gov/idmws/docket_search.asp [enter docket #ER16-1372]

become available on the existing transmission lines that connect wind locations in Wyoming to Midpoint in Idaho. Table 1 below shows potential coal retirements as shown for Preferred Portfolio of PacifiCorp's 2017 Integrated Resource Plan. These coal retirements can potentially make more existing transmission capacity available thereby allowing wind resources in WY to deliver to Midpoint. We recommend that CAISO analyze this further and not draw ATC availability conclusions by only looking at transmission availability on OATI OASIS.

Table 1: Potential Retirement of Coal Generation

Unit	Pmax (MW)	Dispatch level in NTTG 2016/17 base case	Potential Retirement Year[7]
Colstrip 1	330	retired	2022
Colstrip 2	330	retired	2022
Naughton 3	350	retired	2018
Bridger 1	578	531	2028
Bridger 2	578	500	2032
Dave Johnston 1	106	106	2027
Dave Johnston 2	106	106	2027
Dave Johnston 3	220	220	2027
Dave Johnston 4	330	330	2027
Naughton 1	163	122	2029
Naughton 2	201	0	2029

Cost estimate for new transmission from Wyoming to Midpoint, ID

CAISO studies suggest that new transmission will be needed to bring wind resources from WY into Midpoint. CAISO used the plan of service and cost estimate for Gateway West, a transmission project proposed by PacifiCorp. This cost estimate was taken from the RETI 2.0 Project Western Outreach report. However, the full build out of Gateway West should not be required to enable deliveries of wind from WY to Midpoint in light of (i) Gateway West is designed to serve PacifiCorp load (including OR and WA) as opposed to delivering to CA, (ii) the coal retirements referenced above and (iii) favorable wind resources are under development in western WY which will significantly reduce the transmission to Midpoint. The required build out should be further studied by CAISO including an examination of opportunities to re-conductor lines as opposed to building new lines. Including the full build out of Gateway West artificially inflates the cost of the SWIP N option and will skew the results.

Other attributes to be analyzed:

Similar to comments made in previous section on economic studies, CAISO should implement

[7] Retirement year as proposed in the Preferred Portfolio of PacifiCorp's 2017 Integrated Resource Plan. No definitive decision on retirement date has yet been announced or approved.

modelling enhancements to its production cost model for ITP evaluation as well such that intertie scheduling congestion is correctly captured on CAISO's ITC interfaces. CAISO's ATC analysis shows that ~300 MW ATC is available south of Central OR towards COI. As the Brattle study shows, if modelling enhancements are implemented in CAISO economic study models, the intertie congestion that routinely gets recorded to CAISO's Malin & NOB paths does get captured in the studies. Given this historical congestion on this path, an additional value of SWIP North project is that it will make 1000 MW of new scheduling capability at Midpoint for Hydro and other energy schedules from Pacific Northwest that typically get curtailed due to congestion issues on Malin & NOB. These will now have an alternate path to get to California from Central OR to Central ID (as shown on Page 37 of CAISO's Sep 22, 2017 TPP presentation).

Reliability impacts of projects - When analyzing reliability impacts of ITP projects, in addition to the metrics CAISO developed, consideration should also be given to the following metrics for ITP comparison:

(1) Is the line outage of an ITP itself posing any reliability risks to the Bulk Electric System? Will a SPS be required that would trip several generators for loss of the ITP line? If so, what is the impact of the SPS on grid reliability and are there any operational & market implications from this SPS in terms of the need for CAISO to procure additional operating reserves to protect against loss of the ITP line?

(2) Does the ITP project bring any benefits to the WECC system as a whole? For instance is the ITP project a network line (vs a long gen tie line) that could help further reinforce the WECC network and protect against a potential blackout that could be caused by WECC NE-SE separation[8]?

EIM benefits – When comparing ITP projects CAISO should also look into whether projects are helping increase EIM benefits. If an ITP is helping increase EIM transfer capability between multiple EIM regions, this should be a huge benefit to all regions and should be noted accordingly for ITP comparison purposes. For the RETI 2.0 Project Western Outreach report[9] this attribute of ITP projects was accounted for. The report said that "*A number of the projects would enhance the efficiency of the existing (or expanded) EIM as well as a future regional energy market. The SWIP North project is an excellent example of this. The project would increase transfer capability between NV Energy and PacifiCorp, which is currently limited to 430 MW (see Figure 10)".* CAISO's analysis similarly should account for this benefit of ITPs as well.

LS Power thanks CAISO staff for the opportunity to submit these comments.

[8] See WECC procedure related to NE-SE separation at: https://www.wecc.biz/Reliability/WECC-1%20RAS%20Operating%20Procedure%208.22.2016.pdf

[9] See pages 68, 69 of RETI 2.0 Western Outreach Project Report, which is at: *http://docketpublic.energy.ca.gov/PublicDocuments/15-RETI-02/TN214339_20161102T083330_RETI_20_Western_Outreach_Project_Report.pdf*

APPENDIX A:

THE BRATTLE GROUP ITC CONGESTION STUDY

SEPTEMBER, 2017

Modelling Enhancements for CAISO Transmission Planning

The Feasibility and Value of Incorporating Intertie Scheduling Constraints into CAISO's Planning Model

PREPARED FOR

LS Power

PREPARED BY

Judy Chang
Hannes Pfeifenberger
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Michael Hagerty
John Imon Pedtke
Jesse Cohen

October 6, 2017

THE Brattle GROUP

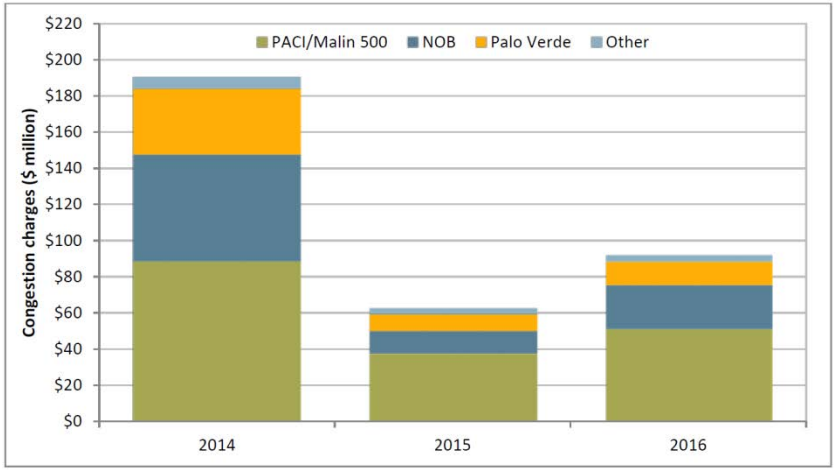
Content

Intertie Scheduling Constraint Overview

Intertie scheduling constraints (ITCs) represent limitations on transfers between CAISO and neighboring Balancing Authorities

- ITCs are contractual limitations on power flow over the transmission system rather than the physical limitations of the transmission lines
- ITC limits are based on the magnitude of CAISO's transmission rights over the interties with neighboring balancing authorities
- Historically, ITC congestion accounts for a significant amount of CAISO market congestion
  - Northwest ITCs account for ~75% of historical ITC congestion, nearly all of which occurs on NOB and Malin

Actual DA Market Import Congestion on Interties



Source: CAISO 2016 Annual Report on Market Issues and Performance, p. 180

Historical Import Congestion on Intertie Scheduling Constraints

Import Region	Intertie Constraint	Import Congestion Charges ($million)					
		2011	2012	2013	2014	2015	2016
Northwest	PACI/Malin 500	$48.9	$84.7	$34.0	$88.7	$37.7	$51.1
	NOB	$25.5	$59.2	$27.8	$58.9	$12.4	$24.3
	Rest of Northwest	$7.3	$3.7	$2.6	$2.9	$0.2	$0.4
	Northwest Total	**$81.6**	**$147.6**	**$64.5**	**$150.5**	**$50.3**	**$75.9**
Southwest	Palo Verde	$25.9	$19.2	$26.4	$36.6	$9.3	$12.9
	Mead	$8.3	$15.2	$2.2	$1.2	$1.3	$1.0
	Rest of Southwest	$3.9	$8.5	$7.4	$4.4	$5.6	$2.0
	Southwest Total	**$38.1**	**$43.0**	**$36.0**	**$42.2**	**$16.1**	**$16.0**
	Other	$0.8	$2.3	$0.2	$0.1	$0.0	$0.9
	Intertie Constraint Total	**$120.6**	**$192.9**	**$100.7**	**$192.8**	**$66.4**	**$92.8**

Source: CAISO 2013-2016 Annual Reports on Market Issues and Performance

Study Purpose

The purpose of this study and report is to:

- Demonstrate that modeling the CAISO system with considerations for Intertie Scheduling Constraints (ITCs) would better reflect actual market conditions than the traditional approach of only modeling physical constraints
- Demonstrate the potential for incorporating ITCs into CAISO transmission planning process by applying such methods/tools to the ISO's 2016/2017 TPP dataset
- Capture scheduling congestion on the order of magnitude of observed levels of day-ahead congestion, particularly on the northern ITCs of NOB and Malin
- Identify additional updates/modifications to the transmission planning assumptions that could result in a more accurate representation of ITC congestion

Limitations of Modelling Congestion in CAISO TPP Studies

The CAISO TPP simulations understate congestion and its impact on wholesale power prices in CAISO, particularly for scheduling constraints at the interfaces with neighboring systems

- GridView does not currently have the capability to model contract paths and associated scheduling constraints in a way that captures the realities of bilateral transactions (e.g., using point-to-point transmission service)
- The ISO's current modeling database does not capture certain hydro import advantages that have a significant impact on import flows and congestion
  - The 2016/2017 TPP database captures BPA's ability to export to CA at a significantly lower carbon hurdle (based on its ACS emissions rate) than generic imports, but does not include similar assumptions for Powerex and Tacoma Power imports, both of which have excess hydro power available for exports to CA at a low CO2 import cost
  - This understates simulated imports from these entities and associated intertie congestion
- The 2016/2017 TPP database uses normal hydro, average transmission outages, and weather-normalized loads
  - Because congestion tends to increase disproportionately during abnormal hydro, outage, or load conditions (e.g., above-average NW hydro and below-average CA hydro), the normalized assumptions do not yield simulation results that reflect the average of likely future outcomes

Study Approach

We incorporated hourly contract path limits on CAISO imports to the assumptions in the ISO's 2016-2017 TPP database

- We used a commercially available production cost simulation model: Power System Optimizer (PSO), the same model used in the SB350 study
- The hourly limits are based on historical 2016 ITC limits posted on CAISO's OASIS website

For this analysis, we simulated two cases for the proof of concept:

- **Case A: 2016/2017 TPP case using PSO (no ITCs incorporated)**
  - Model input assumptions consistent with CAISO 2016/2017 TPP database
  - Provide a baseline against which we can compare the results of modeling the ITCs
- **Case B: Case A *with* ITCs simulated (with updated hurdle rates and with/without enhanced Powerex hydro scheduling assumptions)**
  - Represent ITCs that account for majority of imports/congestions in DA market
  - Modify hurdle rates and hydro assumptions to better capture bilateral trading friction in WECC and import flow from Pacific Northwest into California
  - Illustrate potential modelling assumption enhancements, such as capturing lower CO2 import rates for excess hydro, that can improve representation of scheduling congestion

For the rest of this report, we compare the results from Case A and Case B to illustrate a simulation of the 2026 CAISO system with consistent levels of CAISO congestion and power flow as history.

Major Constraints Between Pacific Northwest and California

A small number of constraints account for the majority of physical and intertie scheduling congestion between the Pacific Northwest and California.

Some of the constraints are physical and others are contractual. Thus, the system planning simulations should reflect both of these types of constraints.

- **CAISO 2016/17 TPP**: represents only the physical constraints (the first two in table below)
- **Brattle Case B**: represents both physical and ITCs constraints

Constraint	Type	Limits (Import/Export from CA)	Description
COI/PACI *California-Oregon Intertie / Pacific AC Intertie*	Physical	4,800 MW / 3,675 MW	Constrains physical flows on the 500-kV line connecting Captain Jack to Olinda and the two 500-kV lines connecting Malin to Round Mountain
PDCI *Pacific DC Intertie*	Physical	3,220 MW / 3,100 MW	Constrains physical flows on DC line connecting Celilo in BPA and Sylmar in LADWP
Malin (into CAISO) *MALIN500*	ITC	3,200 MW / 2,450 MW	Represents CAISO's transmission rights on the COI
NOB (into CAISO) *Nevada-Oregon Border*	ITC	1,591 MW / 1,520 MW	Represents CAISO's transmission rights on the PDCI

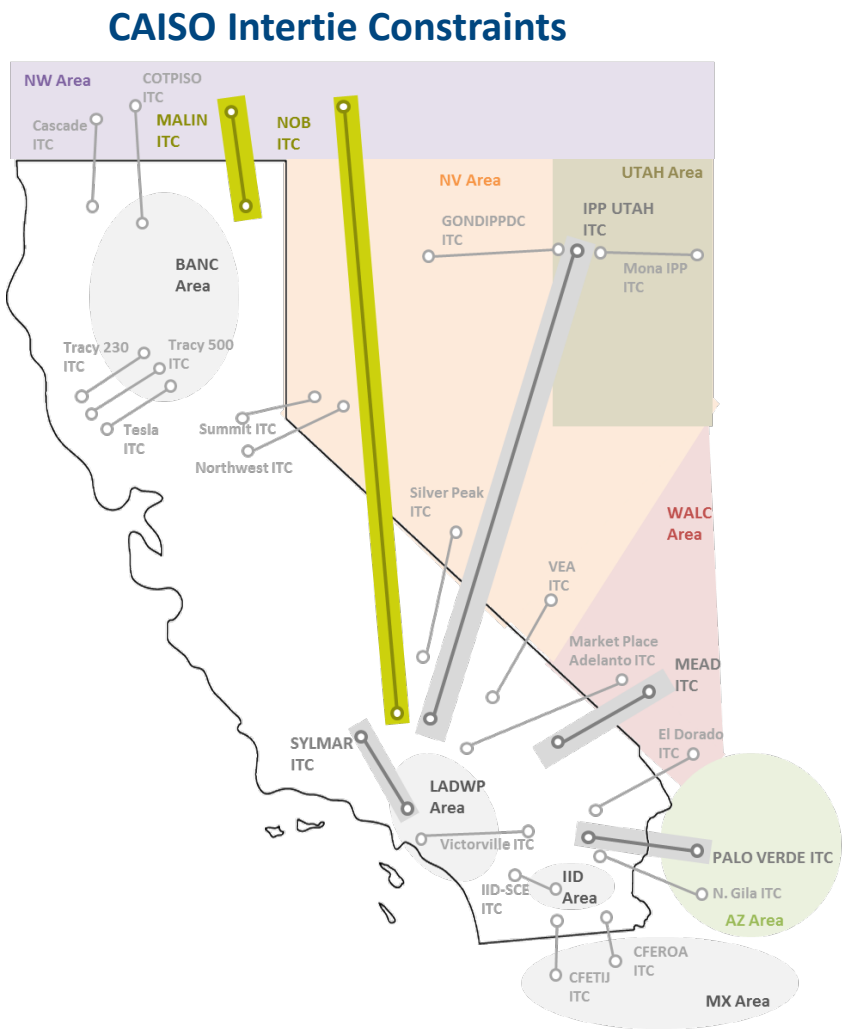
Source: CAISO 2016/2017 TPP database; CAISO Oasis

Note: The reported limits in the table represent the default limits on each constraint; hourly limits vary with outage conditions

Modeled CAISO Intertie Scheduling Constraints

In Case B, we model the six ITCs that capture the majority of CAISO import flow and congestion:

- Northwest Interface ITCs:
  - MALIN
  - NOB
- Southwest Interface ITCs:
  - PALO VERDE
  - MEAD
  - IPPUTAH
  - SYLMAR



Summary of Key Results

Case A reasonably replicates the CAISO's 2016/2017 TPP model

- We find a similar distribution of congestion hours in the Brattle Case A and the CAISO TPP model
- CAISO's 2016/2017 Transmission Plan reports $44 million in physical congestion and 3,200 binding hours, while Brattle Case A finds $15 million in physical congestion and 2,200 binding hours
- Lower congestion in Brattle Case A is conservative in the sense that it does not simulate more congestion than the CAISO TPP model (differences likely attributable to underlying optimization model)

Case B finds 15x more import congestion on the CAISO's northern interface than the CAISO's 2016/2017 TPP model

- Scheduling congestion on both Malin and NOB is $10-$14 million in Case B, compared to <$1 million in congestion on physical import constraints (COI and PDCI) in 2016-17 TPP between Pacific Northwest and California
- The Case B results also show the additional $1 million in physical congestion on the COI and PDCI limits (consistent with CAISO 2016-17 TPP simulation results)
- The magnitude of scheduling congestion on Malin and NOB in Case B more closely aligns with historical congestion on these constraints
- Enhancing NW hydro and CO_2 cost assumptions for hydro imports into CA better align simulations with historical flows, increasing Case B congestion on Malin and NOB by about $4 million (from $10 million to $14 million annually)

Case A Simulation Metrics

Case A vs. 2016/2017 TPP Results

Congestion on Constraints Reported in CAISO 2016/2017 Transmission Plan

Transmission Constraint	2016/2017 TPP		Case A	
	Congestion Charges (M$)	Duration (hr)	Congestion Charges (M$)	Duration (hr)
BOB SS (VEA) - MEAD S 230 kV line	$23.72	600	$7.41	437
PG&E LCR	$9.73	684	$2.83	403
Path 26	$5.03	320	$1.78	650
PG&E /TID Exchequer	$1.68	651	$0.02	12
J. HINDS-MIRAGE 230 kV line #1	$1.09	187	$0.44	120
COI	$0.84	120	$1.11	363
Path 45	$0.63	655	$0.20	27
SCE LCR	$0.49	34	$0.00	0
Path 15/CC	$0.44	32	$1.64	90
Reported CAISO 2016-17 Total:	**$43.65**	**3,283**	**$15.44**	**2,102**

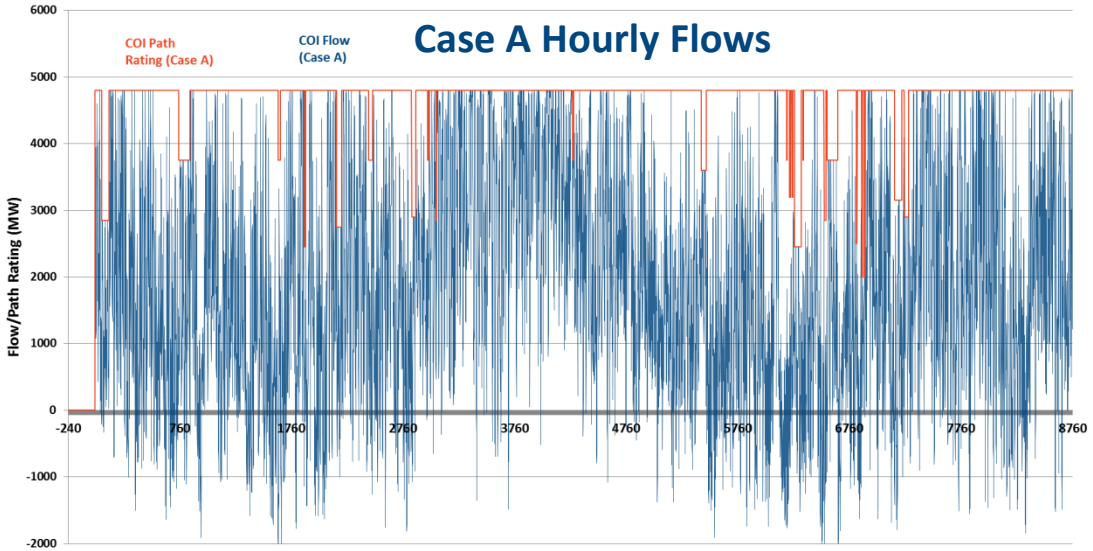
Source: CAISO 2016/2017 Board Approved Transmission Plan, pp. 179
Note: We exclude from the table constraints that show < $0.1 million in congestion in both Case A and the 2016/2017 Transmission Plan

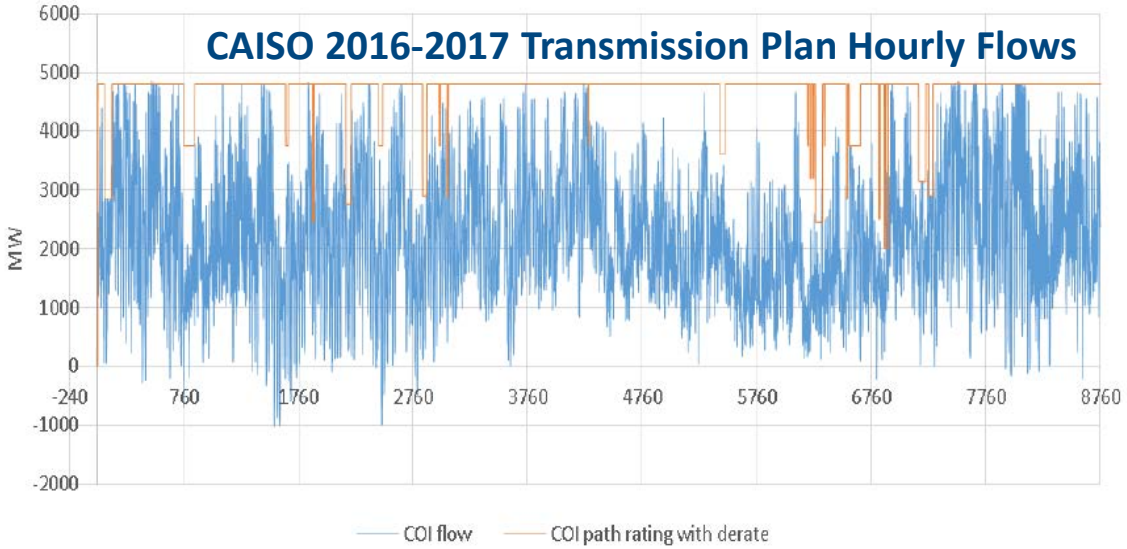
Case A congestion amounts to $15.4 million over 2,102 hours on the set of constraints reported in the CAISO's 2016/2017 Transmission Plan

- COI congestion in Case A is similar to that in CAISO's TPP model at ~$1 million
- Pattern of congestion across constraints in Case A is similar to the CAISO's TPP model
- More than 50% of the difference in congestion is attributable to two constraints:
  - BOB SS-MEAD line constraint (286 MW line in Nevada) and PG&E LCR constraints
- Remaining differences in congestion in the simulations likely due to differences in underlying modeling frameworks (such as using physical vs. contractual wheeling rates and heuristic vs. mixed integer programming optimization unit commitment in GridView vs. in PSO)
- We are unable to compare congestion on constraints that are not in the CAISO-reported list

Case A

Comparison of COI Path Flow and Ratings





- COI flows are similar between Case A and CAISO's 2016/2017 TPP , but greater hourly variations in Case A compared to the CAISO's 2016/2017 TPP model
- We have not analyzed the drivers of the difference in flows (Will need more detailed results from the TPP model to be able to compare)
- Potential drivers of differences:
  - Realized operation of phase shifters, in particular the Path 76 phase shifter at Alturas
  - Regional commitment patterns due to underlying unit commitment approach

Source: CAISO 2016/2017 Board Approved Transmission Plan, pp. 191

Case B Results

Case B

Overview of Case B

Brattle Case B simulates the ITC limitations, enhances the use of hurdle rates over contract paths and hydro scheduling assumptions to demonstrate that congestion over ITCs can be simulated with a more accurately representation of WECC system

Case B1: ITC Implementation

- Add to Case A intertie scheduling constraints based on 2016 limits and relax CAISO net-export constraint
  - Assume that explicitly representing the contractual limits between CAISO and its neighbors via the ITCs supersedes need to enforce net-export constraint
- Also updated hurdle rates to those used in SB350 Study (increases hurdle rates by $2-$9/MWh)
  - SB350 hurdle rates based on 2016 short-term, off-peak wheeling charges and also capture other trading friction and scheduling fees not captured in the 2016/2017 TPP database hurdle rates

Case B2: Illustrative Enhanced Hydro Scheduling and Hurdle Rate Assumptions

- Simulate BC Hydro's scheduling against weighted average of CAISO and BC net load (15% CAISO, 85% BC)
  - Represents incentives for BC hydro to capture higher prices in CA during CAISO peak net load
- Add zero-hurdle contract path from BC Hydro to Malin/NOB based on historical levels of Powerex transactions at these interties
  - Implemented rough proxy for Powerex long-term transmission contracts (assumed ~1000 MW to Malin and NOB)
- Add low CO_2 charges for hydro imports to CA from BC Hydro (similar to treatment of hydro imports from BPA)
  - Amount of hydro imports varies monthly; based on quantity of modeled hydro in excess of modeled load in BC
  - Reduced CO_2 charges for a limited quantity of imports from $14.74/MWh to Powerex rate of $0.66/MWh
- In the absence of publicly-available data, Case B2 only utilized informed placeholder assumptions for known market conditions that demonstrate importance of these inputs and, if refined, could more accurately capture scheduling congestion

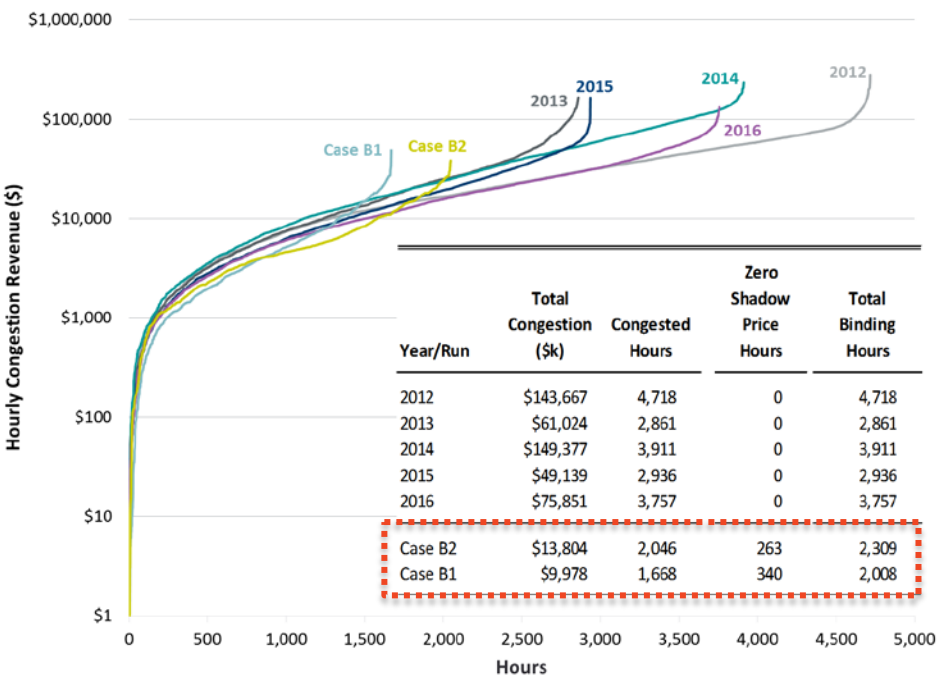
Case B

Modeled vs. Historical Congestion over the Interties

Case B's hours of congestion and congestion costs over Malin+NOB are still below historical levels, but are more consistent with the observed historical congestion levels than the current CAISO simulation results

- Case B2 finds 15x more congestion at Malin+NOB than ISO finds on COI and PDCI
  - CAISO simulations show less than $1 million in physical congestion on COI and PDCI in 2016/17 Transmission Plan
  - We find similar physical congestion on COI, as well as an additional $10-$14 million in congestion on the Malin and NOB intertie scheduling constraints
- Case B2 results in 2,309 total binding hours on Malin+NOB, compared to 2,800-4,700 hours historically
  - CAISO simulations show only 120 congested hours on COI, none on PDCI

Cases B1 and B2 and Historical Congestion on Malin and NOB Interties



Year/Run	Total Congestion ($k)	Congested Hours	Zero Shadow Price Hours	Total Binding Hours
2012	$143,667	4,718	0	4,718
2013	$61,024	2,861	0	2,861
2014	$149,377	3,911	0	3,911
2015	$49,139	2,936	0	2,936
2016	$75,851	3,757	0	3,757
Case B2	$13,804	2,046	263	2,309
Case B1	$9,978	1,668	340	2,008

Source: Historical data downloaded from CAISO OASIS; Cases B1 and B2 based on PSO simulations

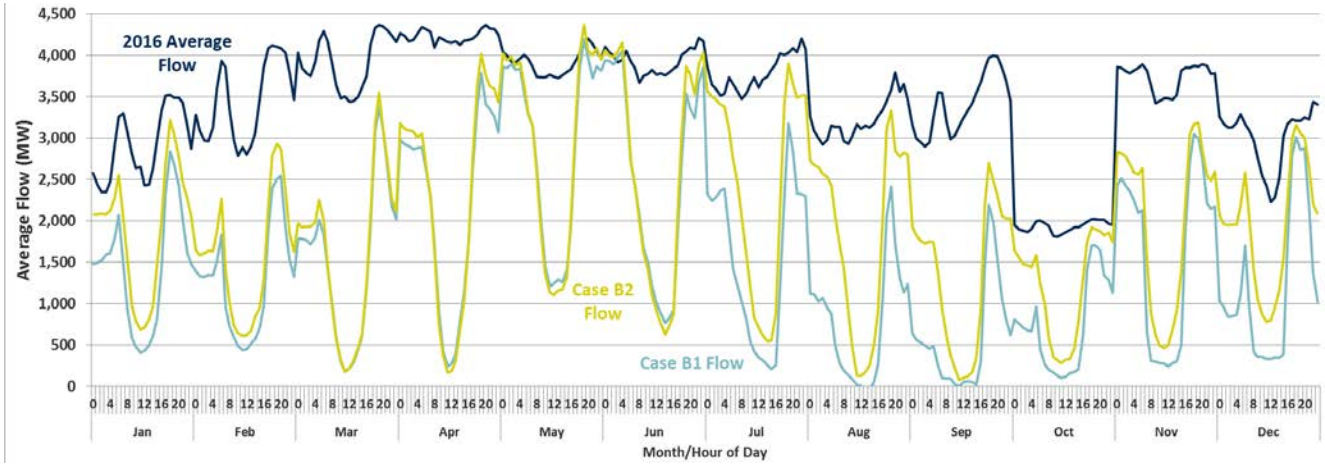
Case B

Modeled vs Historical Flows over the Interties

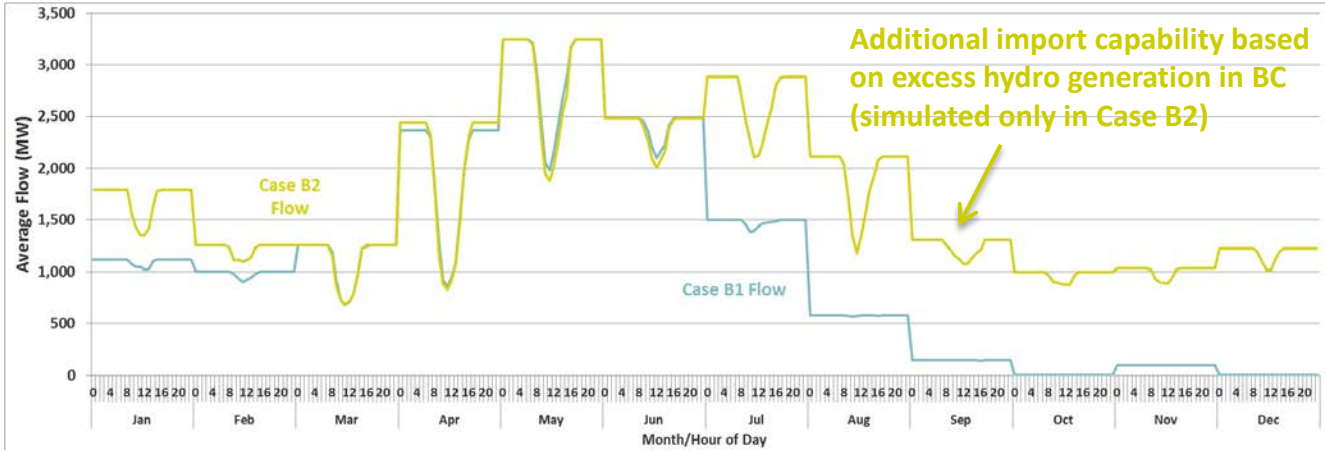
Case B flows over Malin+NOB intertie are not as high as historical levels, but are similar in high-hydro months:

- Case B1 and B2 flows are lower than historical in the daytime partly due to higher solar generation in 2026 than in historical years
- Allowing BC Hydro/Powerex to import at the reduced CO_2 emissions rate in Case B2 increases the flows over NOB and Malin, more consistent with historical flows
- Case B2 simulations show the importance of capturing assumptions about hydro scheduling and CO_2 costs to align modeled system with actual system experience

Average Flow on Malin+NOB ITCs by Month and Hour-of-Day



Average CA Imports at the Low CO2 Rate by Month and Hour-of-Day



Source: Historical data downloaded from CAISO OASIS

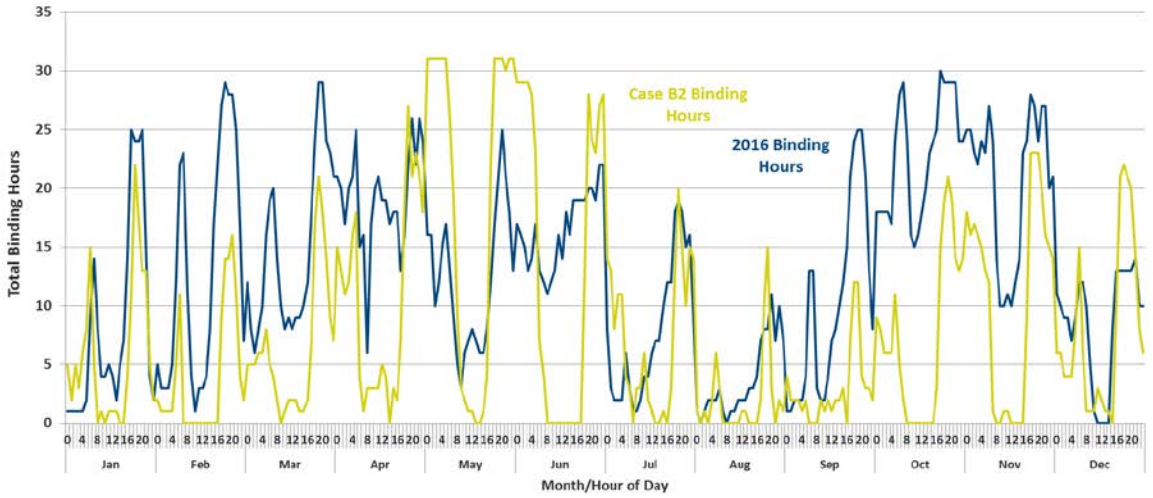
Case B

Modeled vs Historical ITC Congestion over Time

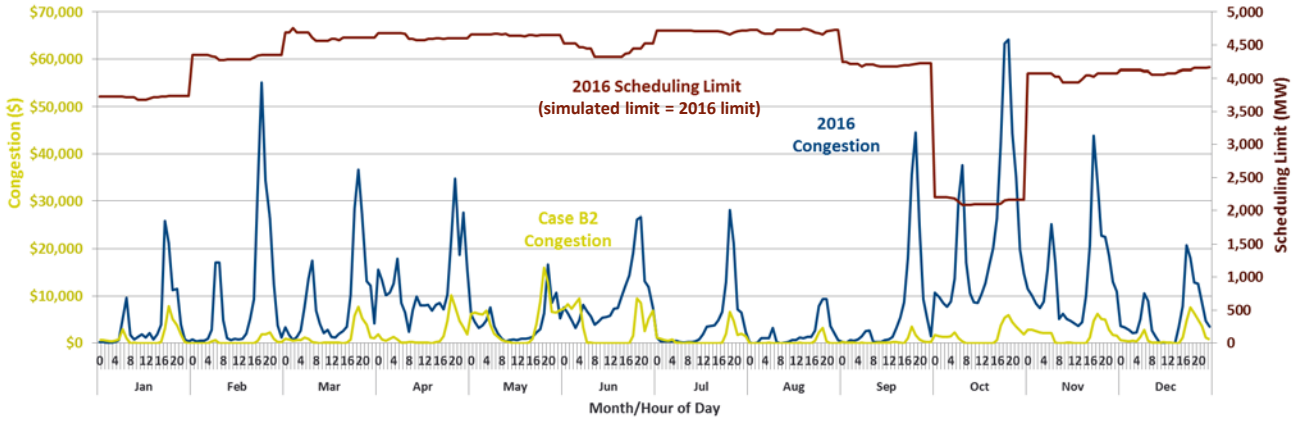
Case B's congestion pattern over Malin+NOB track historical levels

- The number of binding hours is closely aligned between modeled Case B and historical levels
- But the congestion costs are lower in Case B compared to historical levels
- The periods of highest modeled congestion coincide with the high hydro periods

Modeled vs. Historical Malin+NOB Binding Hours by Month and Hour-of-Day



Modeled vs. Historical Malin+NOB Congestion Cost by Month and Hour-of-Day



Source: Historical data downloaded from CAISO OASIS

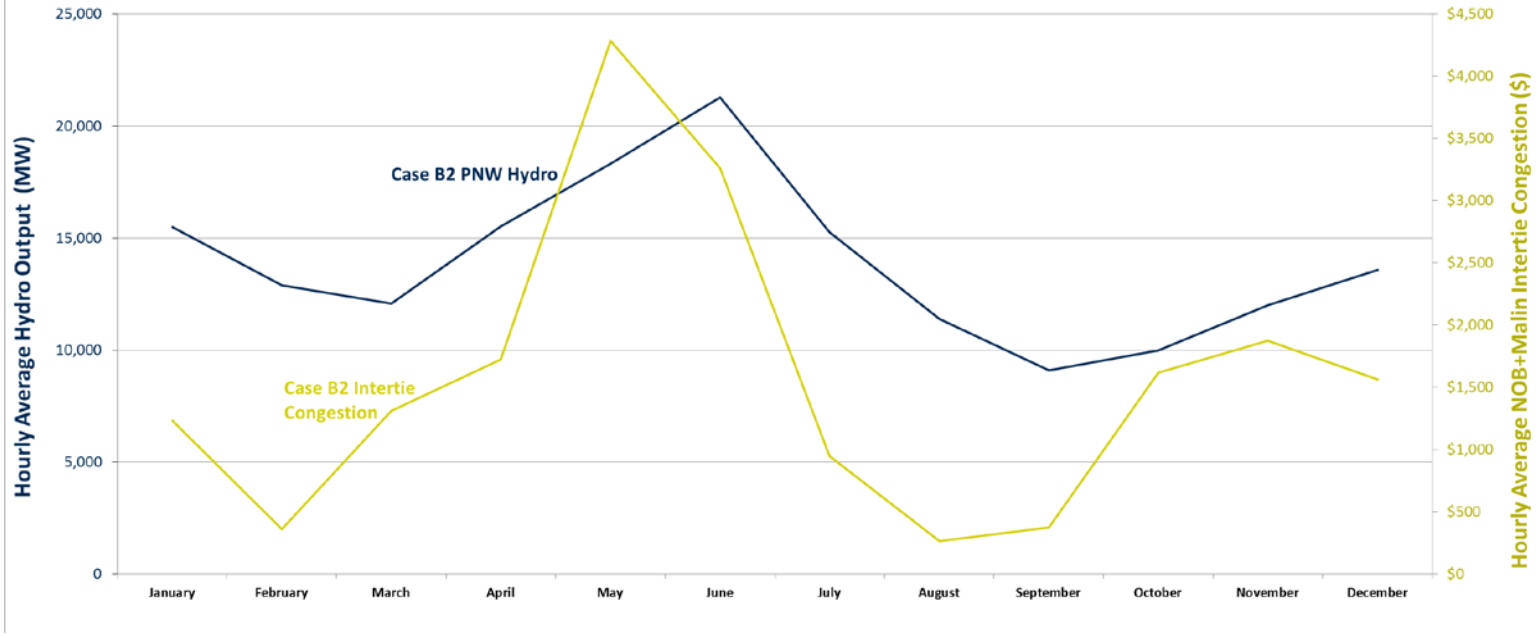
Case B

Modeled Hydro and ITC Congestion

Hydro conditions in the Pacific Northwest are a significant driver of scheduling congestion over the NOB and Malin ITCs

- Highest congestion periods over Malin and NOB occur in the spring when hydro output from the Pacific Northwest is peaking
- Periods of lower Malin and NOB congestion coincide with lower hydro output from the Pacific Northwest

Case B2 Monthly Pacific Northwest Hydro Output and NOB+Malin Congestion



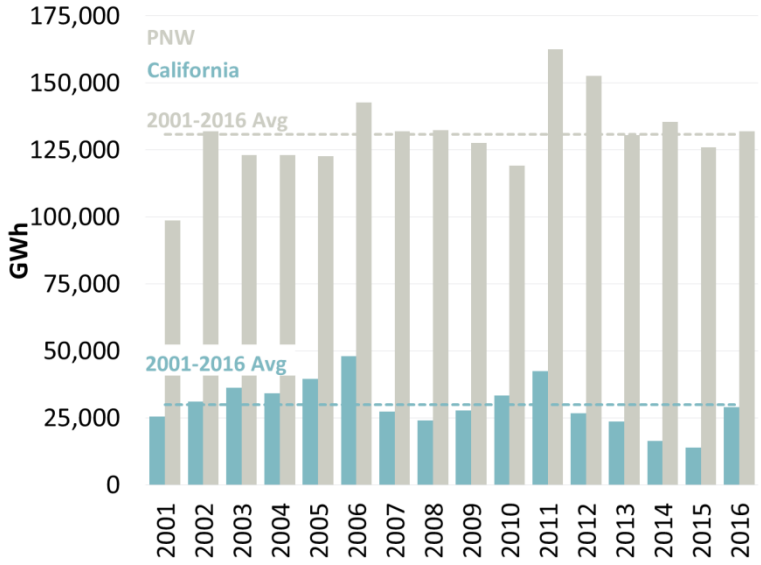
Case B

Historical Hydro Patterns

Over the past five years California and Pacific Northwest hydro have moved in different directions (for example, in 2012, CA had a low hydro year, but the Pacific Northwest experienced a high hydro year)

- The simulated 2026 year uses "average" (2009) hydro levels for both CA and the Pacific Northwest. Thus, other hydro conditions are not captured in the simulation
- However, actually hydro conditions observed historically since 2011 (high NW and/or low CA hydro) contribute significantly to high flows and congestion over Malin and NOB intertie constraints

Historical Annual Hydro Output



Source: EIA 906/920/923 filings and Brattle Analysis

Historical CA and PNW Hydro

	Hydro Output (GWh)		Percent Change from 2001-2016 Avg Output		Hydro with Respect to Avg	
	CA	PNW	CA	PNW	CA	PNW
2012	26,837	152,740	-10.5%	16.8%	Low	Very High
2013	23,755	130,580	-20.8%	-0.2%	Very Low	Avg
2014	16,409	135,494	-45.3%	3.6%	Very Low	High
2015	13,861	125,952	-53.8%	-3.7%	Very Low	Low
2016	28,945	131,986	-3.5%	0.9%	Low	Avg

Source: EIA 906/920/923 filings and Brattle Analysis

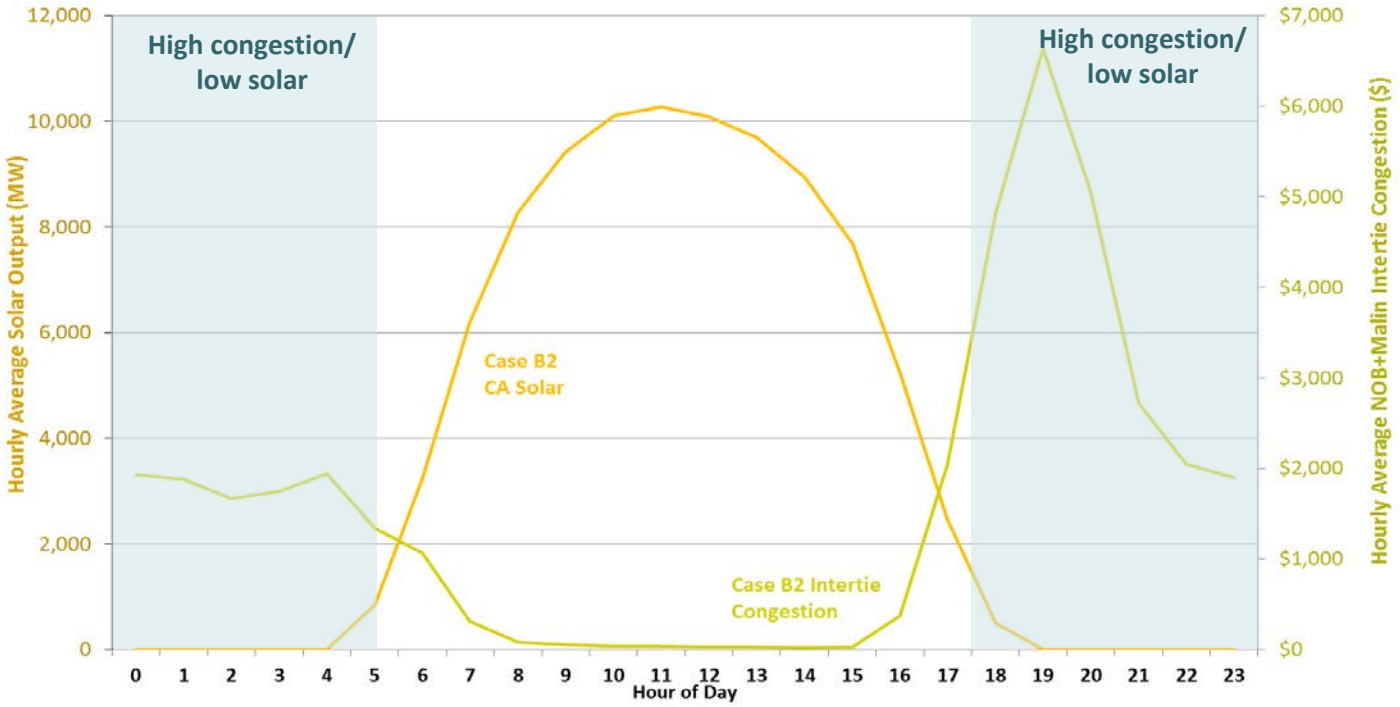
Case B

Impact of Solar on Congestion over Malin and NOB ITC

The magnitude of California's installed solar generation is not a major driver of congestion over the Northern ITCs

- The majority of Malin and NOB ITC congestion in Case B2 occurs during periods of low/no solar output in California (when net load peaks and during the night)
- Increasing solar capacity in the California will have a limited impact on reducing import congestion on Malin and NOB ITCs

Case B2 Hourly Average California Solar Output and NOB+Malin Congestion



Conclusions and Recommendations

Conclusions and Recommendations

We demonstrate the capability to represent realistic levels of CAISO intertie scheduling congestion in transmission planning models

- We find $10-$14 million in congestion on the Malin and NOB ITCs, which is over 15x higher than the NW import congestion in CAISO's 2016/2017 TPP simulations

We show that enhancing Northwest hydro modeling assumptions can improve the representation of system conditions on Malin and NOB

- Illustrative simulations with lower-carbon charges for imports from Powerex better align modeled and historical flow and increase modeled Malin and NOB ITC congestion by $4 million (from $10 million to $14 million)
- Additional enhancements to hydro and hurdle assumptions could represent the system more realistically, and potentially increase the $14 million in Malin+NOB simulated congestion in our Case B2 to more closely align simulation results with the historical congestion ranges of $49-$149 million for these ITCs

We recommend CAISO explore incorporating intertie scheduling constraints and an enhanced NW hydro representation into its simulation of the 2017/2018 TPP Economic Studies to more accurately assess benefits of the future CAISO transmission system

Additional Factors Not Yet Simulated

Other factors that could align simulation results with historical system conditions:

- Model additional hydro condition scenarios (e.g., high/low hydro from Pacific Northwest)
  - Every year since 2011 deviated significantly from "average" hydro conditions, driving more power flows from the north into California
  - Modeling CA and Pacific Northwest hydro as "average" will understate the actual flows into CA
- Capture low CO_2 costs for all Asset Controlling Supplier (ACS) improves the accuracy of the simulations
  - Imposing full carbon charges on CA imports from all BAAs except BPA dampens flows into CA
  - Should model Powerex and Tacoma hydro sales flowing into CA at low carbon charges
  - The potential high impact of improving this assumptions is demonstrated in Case B2
- Model scenarios with more extreme load conditions
  - Model currently uses weather-normalized load for all areas. This is an unlikely "average" case
  - More extreme load conditions in the Pacific Northwest and CA would reflect greater volatility in power flows and congestion
  - Simulating only weather normalized load levels likely understates flows and congestion levels
- Model scenarios with more severe transmission outage conditions
  - Some historical years, such as 2014, had extended high-impact transmission outages that are not reflected in the "average year" outage data used in transmission planning,
  - Such above-average outage conditions will reoccur in the future and tend to have a disproportionately high impact on congestion which is not captured in simulations

Modeled vs. Real-World Bilateral Friction

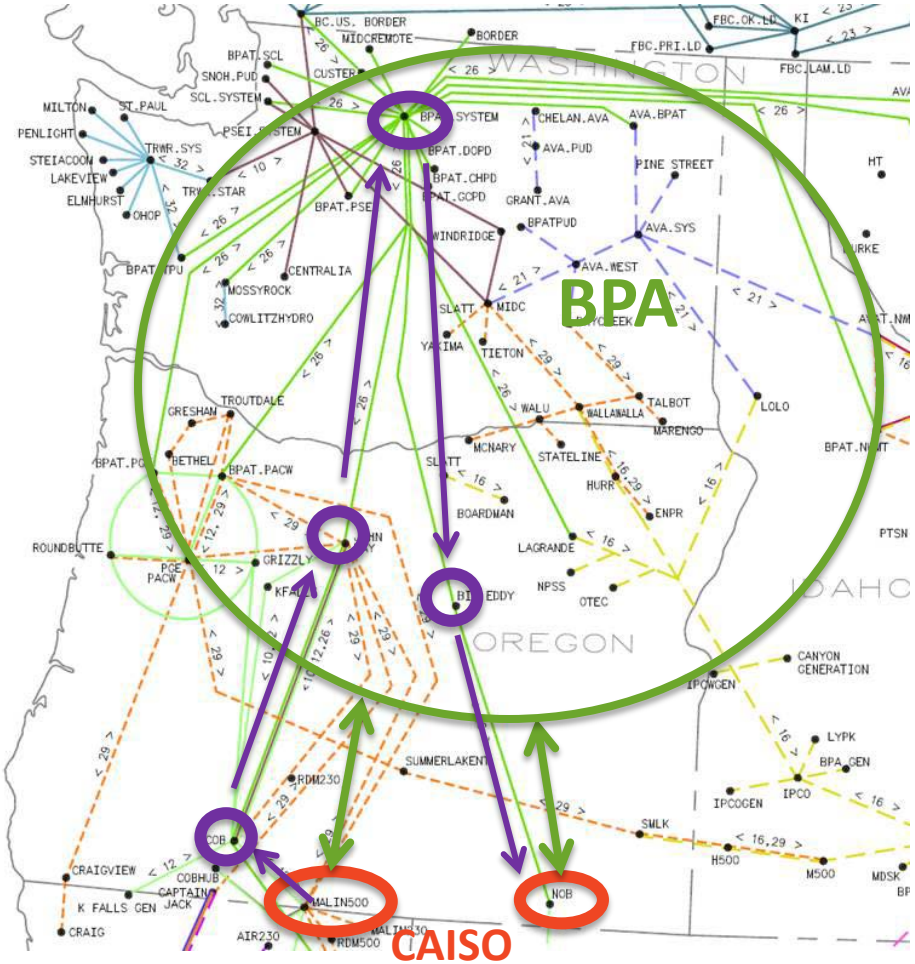
Conventional modeling of contract paths typically assumes each balancing area is a single scheduling point (the green BPA bubble in the figure)

- Provides unlimited capability and flexibility for scheduling transactions within each BA to reach interconnections with other BAs
- The bilateral frictions encountered when moving power from one point to another are not fully captured
  - e.g., going from Malin to NOB in the figure requires just two transactions in the simulations—into and out of the BPA bubble

In reality, BAs are composed of multiple scheduling points (see map of WECC scheduling points in the figure) with limited ATC

- Transfers between scheduling points through a BA may require several transactions
  - e.g., the purple bubbles and arrows in the figure
- Even when modeling limitations on BA-to-BA transactions (as represented by the ITCs), this still understates the frictions and more limited flexibility encountered by bilateral transactions within/between BAs

Modeled vs Real-World Bilateral Scheduling



Source: WECC

Power System Optimizer (PSO)

PSO is a state-of-the-art nodal production cost simulation model developed by Polaris Systems Optimization, Inc.

- Similar to GridView, Promod, GE-MAPS, Plexos, Dayzer
- Simulates security-constrained commitment and economic dispatch of generation interconnected to transmission system
- Detailed transmission representation (path ratings, thermal constraints, contract path limits, contingency constraints, etc.)
- Contract path layer (captures realities of point-to-point scheduling)
- Highly flexible reserve modelling (spin, regulation, load following, user-configurable timing and parameters)
- Configurable “decisions cycles” simulate availability of information and timeframes of operations and (e.g., day-ahead, hour-ahead, real-time)
- Detailed energy storage representation (MW capacity, MWh capacity, ramp rates, efficiency)

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Note:

The views expressed in this presentation are strictly those of the presenter and do not necessarily state or reflect the views of *The Brattle Group, Inc*.

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Ms. Chang has presented at a variety of industry conferences and has advised international and multilateral agencies on the valuation of renewable energy investments. She holds a BSc. In Electrical Engineering from University of California, Davis, and Masters in Public Policy from Harvard Kennedy School, is a member of the Board of Directors of The Brattle Group, and the founding Director of New England Women in Energy and the Environment.

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Hannes has extensive experience in the economic analyses of wholesale power markets and transmission systems. His recent experience includes reviews of RTO capacity market and resource adequacy designs, testimony in contract disputes, and the analysis of transmission benefits, cost allocation, and rate design. He has performed market assessments, market design reviews, asset valuations, and cost-benefit studies for investor-owned utilities, independent system operators, transmission companies, regulatory agencies, public power companies, and generators across North America.

Hannes received an M.A. in Economics and Finance from Brandeis University and an M.S. in Power Engineering and Energy Economics from the University of Technology in Vienna, Austria.

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Attachment B: LS Power comments on the 2018/19 TPP Study Plan and Economic Study Request

CAISO 2018/19 TPP Study Plan: Stakeholder Comments

Submitted by	Company	Date Submitted
Sandeep Arora (sarora@lspower.com) (925) 201 5252	LS Power Development, LLC	3/14/18

LS Power appreciates the opportunity to provide comments on the CAISO 2018/19 Draft Study Plan.

LS Power is hereby submitting an economic study request to CAISO for the 2018/19 Transmission Plan. The request is to study scheduling based congestion (such as recorded in CAISO Department of Market Monitoring reports) in addition to flow based congestion, on CAISO's intertie interfaces with the Pacific Northwest, namely the California Oregon Intertie (COI), Pacific AC Intertie (PACI) and Nevada-Oregon Border (NOB). In addition to this request, LS Power is also hereby submitting its Southwest Intertie Project North (SWIP-North) as an Economic project that would improve transfer capabilities between the Pacific Northwest and California.

PACI, NOB & COI Congestion:

For the past three planning cycles, LS Power has registered its concern that CAISO's economic studies performed for the Transmission Planning Process (TPP) consistently fail to capture the tens to hundreds of million $'s in annual congestion costs along the PACI and NOB interfaces, and therefore consistently fails to identify economic benefits related to transmission solutions submitted in the annual TPP process. Since 2011, actual PACI and NOB congestion per CAISO DMM reports has been in the range of $50 mm to $145 mm per year. This contrasts with the less than $1mm of annual congestion predicted in CAISO planning studies for the COI path[1]. It is estimated that the SWIP-North project, which LS Power has submitted in the past three TPP cycles, reduces COI flows by ~300 MW or more and based on CAISO's analysis, reduces congestion hours on COI by 39%. Given that insignificant congestion gets quantified in CAISO studies, the economic savings offered by projects such as SWIP-North continue to be lost as do the benefits of increasing capacity between California and the Pacific Northwest. Resolving the discrepancy between real world congestion vs the congestion predicted through studies is even more important now given the February 15, 2018 letter[2] from CEC and CPUC requesting that the CAISO do a special sensitivity study

[1] California Oregon Intertie (COI) comprises of three transmission lines that have a combined flow limit of 4800 MW N-S. CAISO TPP studies enforce this flow limit and capture any congestion on this path. In the Day Ahead scheduling world, congestion is witnessed across the Pacific AC Intertie (PACI) and Nevada-Oregon Border (NOB) scheduling interfaces. PACI is a subset of COI and has a scheduling limit of 3200 MW which represents scheduling rights of CAISO member entities on COI path. NOB is the scheduling interface for Pacific DC Intertie. It is rated at 3220 MW N-S and the transmission capacity is allocated between CAISO member entities and LADWP.

[2] http://www.caiso.com/Documents/CPUCandCECLettertoISO-Feb152018.pdf

in its current 2018/19 TPP that looks at increasing the transfer of low-carbon supplies to California from the Pacific Northwest. As CAISO performs this special sensitivity study it should consider SWIP-North transmission project as a solution that can not only improve transfer capability between BPA and CAISO along the existing COI corridor by ~300 MW, but can also provide a new diverse transmission path with an additional 1000 MW transfer capability into/from California through a 500 kV AC transmission line from Midpoint 500 kV substation to Eldorado 500 kV substation. The efforts on this study will be well served if CAISO first correctly captures the economic congestion that takes place on PACI, NOB interfaces today and looks for options to alleviate this. Benefits of projects such as SWIP-North, that not only help improve transfer capability but also provide reliability and future policy benefits, can only be correctly quantified if this congestion is accurately modelled in the study.

Modelling recommendations to correctly quantify PACI & NOB congestion:

In order to understand the discrepancies between congestion quantified by CAISO planning studies and real world congestion as shown in CAISO DMM reports, last year LS Power contracted with The Brattle Group (Brattle) to conduct an economic study to capture PACI & NOB congestion. Brattle's findings[3] were submitted to CAISO as part of comments filed by LS Power in Oct 2017 for 2017/18 TPP. A brief summary of Brattle work is outlined below. We request CAISO staff to implement Brattle's recommendations to improve its economic study models for 2018/19 TPP. These modeling enhancements are a necessary first step to evaluate any potential increase in intertie capacity between California and the Pacific Northwest.

Brattle used CAISO's production cost simulation model from 2016/17 TPP and converted this from CAISO's native GridView format for use in the Power System Optimizer (PSO), another commercially available production cost simulation software. PSO was used because it has the capability to simulate contract-path transactions and congestion on scheduling constraints. After benchmarking the PSO case with native CAISO case, Brattle incorporated the following enhancements to the PSO model:

(a) added Intertie scheduling constraints to create a more accurate representation of WECC-wide scheduling and congestion
(b) updated hurdle rates to better reflect the trading frictions that exist in bilateral scheduling, using assumptions from the SB350 study.
(c) included a case with preliminary assumptions about existing contract paths and reduced hurdle rates for hydro resources from BC Hydro's system to reflect the reality that PowerEx likely has long-term transmission reservations to reach the CAISO's Malin and NOB scheduling points and faces very low CO_2 costs for at least a portion of its hydro imports into California

As a result of these enhancements, the simulated flows on the Malin and NOB paths increased and were noted to be comparable to historical flows in some periods of similar net load and hydro conditions. The simulated 2026 power flows were lower than historical flows during the daytime hours due to the incremental solar generation that is projected to be online by 2026. However, the predicted flows and associated congestion on intertie scheduling constraints, such as Malin and

[3] LS Power comments (including Brattle findings) filed under 2017/18 TPP can be found at:
http://www.caiso.com/Documents/LSPComments_2017-2018PreliminaryReliabilityResults.pdf

NOB, remained high during the evening and night hours when solar generation is offline suggesting that solar buildout in California doesn't significantly reduce PACI/NOB congestion.

Key Findings & Recommendations:

(1) The study concluded that implementing select modelling enhancements that reflect contract path scheduling and intertie scheduling constraints significantly improves the realism of simulated congestion of these paths, partially resolving the large discrepancy between recorded historical congestion and congestion predicted by TPP studies
(2) The study also showed that the increasing magnitude of California's installed solar capacity is not a major driver in terms of reducing intertie congestion on paths such as Malin and NOB since this congestion typically occurs during periods of no/low solar output in California.
(3) The Brattle study makes specific recommendations on additional modelling enhancements that should be considered to simulate realistic levels of congestion on Malin and NOB

Economic Study Request:

LS Power hereby submits SWIP-North as an economic project and requests CAISO to study this in the 2018/19 planning cycle. SWIP-North is comprised of a 500 kV transmission line from Midpoint substation to Robinson Summit substation. Additional details of SWIP-North are included in the submission of SWIP-North as an Interregional Transmission Project in March 2016 under the 2016/17 TPP. This project will be submitted again in March 2018 under the 2018/19 TPP. After SWIP-North is built, LS Power's affiliate will attain approximately 1000 MW of new[4] transmission capacity that will become available on the existing 500 kV transmission line that connects Robinson Summit to Harry Allen substation ("ON Line"), as per the Transmission Use and Capacity Exchange Agreement ("TUA") among LS Power affiliates and NV Energy, which is further described below. LS Power hereby proposes this new additional ~1000 MW capacity to be dedicated for CAISO use. In addition, the new 500 kV line from Harry Allen to Eldorado was approved by CAISO to be in-service by 2020. Upon completion of the Harry Allen to Eldorado project, Harry Allen will be a CAISO delivery point. Hence, if SWIP-North was selected by CAISO, CAISO will have access to a complete 500 kV path from Midpoint to Eldorado, approximately 575 miles.

Pursuant to the TUA with NV Energy, once SWIP-North is built there would be an exchange of capacity between LS Power affiliates and NV Energy. Upon completion of SWIP-North, NV Energy would get a share of the capacity between Midpoint and Robinson Summit and LS Power's Great Basin affiliate would get a share of capacity between Robinson Summit and Harry Allen, without either party having to pay any amount to the other. As a result of this capacity exchange, LS Power's affiliate would have bidirectional transmission capacity on the entire path from Midpoint to Harry Allen, estimated at approximately 1000 MW. Therefore, LS Power's economic study request is that CAISO study the benefits of approximately 1000 MW of bidirectional transmission capacity between Midpoint and Harry Allen, which would be available to the CAISO market upon completion of construction of SWIP-North.

[4] The Robinson Summit to Harry Allen 500 kV line is currently limited to ~975 MW of transmission capacity. Building SWIP North will increase transmission capacity of this line by ~1000 MW, which will be available to LS Power's affiliate and can be dedicated for CAISO use.

In addition to the economic benefits that CAISO calculates from Energy Savings and Congestion reduction, CAISO should also estimate Capacity Benefits from the incremental import capability that SWIP-North will provide.

LS Power thanks CAISO for the opportunity to provide these comments and looks forward to working with CAISO staff as it conducts economic study and the special sensitivity study to improve transfers to/from Pacific Northwest into California.

Attachment C: Brattle report on Benefits of SWIP-North (May 31, 2016), 2016/17 ITP submission

Benefits of the Southwest Intertie Project-North (SWIP North)

PREPARED FOR

GREAT BASIN TRANSMISSION, LLC

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MARCH 31, 2016

THE Brattle GROUP

This report was prepared for Great Basin Transmission, LLC. 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, particularly members of LS Power.

Table of Contents

Executive Summary

The Southwest Intertie Project-North (SWIP North) is a planned 275 mile 500 kV alternating current (AC) transmission line from the Midpoint substation in southern Idaho to the Robinson Summit substation in central Nevada. The addition of SWIP North (in conjunction with the recently completed One Nevada Line and CAISO-approved Harry Allen to Eldorado project) will create a major new transmission path that runs parallel to the existing constrained transmission corridors between the northwestern and southwestern portions of the Western Electricity Coordinating Council (WECC) region and connects low-cost renewable-generation areas in Wyoming to markets in California, Nevada, and Arizona.

We analyzed the potential benefits of SWIP North to the members of the Northern Tier Transmission Group (NTTG), WestConnect, and the California ISO (CAISO) for consideration in the upcoming Interregional Transmission Planning (ITP) process. Our analysis identified the following benefits of SWIP North:

- *Congestion Relief over COI*: SWIP North is expected to provide approximately 300 MW of congestion relief to the highly utilized California-Oregon Interface (COI). Annual congestion charges along the California-Oregon corridor (including COI and North-of-Oregon Border Intertie) have ranged from $60 million to $150 million per year from 2012 through 2014. Though CAISO's existing market simulation approach does not capture the real-world COI congestion, and understates the congestion relief provided by SWIP North, the CAISO analysis of SWIP North found that the project reduces congested hours on COI by 39%. Applying these reductions to the actual historical congestion charges, the project would potentially reduce congestion charges by $23 million to $59 million per year. Such congestion relief would decrease system-wide production costs, reduce utilities' purchase costs, or increase their sales revenues—benefits that likely would accrue primarily in NTTG and CAISO.
- *Energy Market Value*: SWIP North is estimated to provide a wholesale energy market value (a bookend estimate of production cost savings) in the range of $110 million to $150 million per year. This value is consistent with (1) projecting historical real-time wholesale energy market prices differences through 2030 and (2) an analysis of future production cost savings based on Center for Energy Efficiency and Renewable Technologies (CEERT) and National Renewable Energy Laboratory (NREL) market simulations. We expect the actual benefits will be higher than those estimated in the CEERT/NREL analysis because their simulations are based on normalized conditions without taking into consideration uncertainties in load, weather, hydro and renewable generation, unexpected generation outages, and transmission outages. NREL's prior Low Carbon Grid Study (LCGS) shows that SWIP North is highly utilized across several simulated high-renewable-generation scenarios. The direction of flow across SWIP North differs depending on market conditions, with annual net transfers of 2,600 gigawatt-hours (GWh) north-to-south in high hydro years and 6,600 GWh south-

to-north in low hydro years. The LCGS simulations show that the hourly changes in daily SWIP North flow pattern provide 3,000 MW of ramping capacity that will reduce customer costs in addition to the production cost savings (particularly in CAISO) by avoiding solar curtailments and reducing the need for flexible capacity procurement.

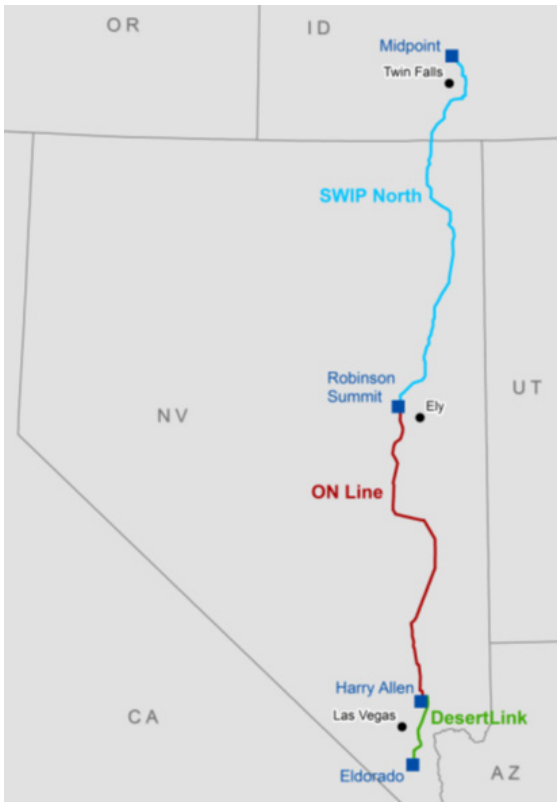
- *Energy Imbalance Market (EIM) Benefits*: SWIP North adds transfer capability between PacifiCorp and CAISO, which, as shown in previous studies, increases EIM-related benefits. For example, increasing transfer capability by 400 MW is expected to increase annual savings up to $26 million.
- *Load Diversity Benefits and Capacity Cost Savings*: The additional transfer capability provided by SWIP North between balancing areas will allow for capacity sharing associated with load diversity across the balancing areas. For example, the additional transfer capability between PacifiCorp and CAISO would allow PacifiCorp to reduce its reserve margin requirements by 390 MW in 2020 and 450 MW in 2030. We estimate the potential savings of avoided capacity costs to be $15 million in 2020 and $45 million in 2030. SWIP North would facilitate sharing of planning reserves across balancing areas in NTTG and WestConnect by providing a more direct connection between the respective systems. The transfer capability provided by SWIP North between regions will allow the regions to take advantage of surplus capacity in other regions or access new capacity to be built in locations with the lowest capital costs. These additional benefits have not been quantified in this report.
- *Insurance Value*: SWIP North will mitigate the adverse impacts of extreme events and challenging future market conditions on electricity market participants and retail customer rates, providing "insurance value" against the risks associated with potentially very-high-cost events and future developments. For example, the energy market value associated with SWIP North, estimated based on historical price differences (as a book-end estimate for production cost savings), spiked to $127 million in 2012. This value is more than twice the $53 million average under "normal" conditions for the several years before and after 2012. The addition of SWIP North will mitigate the impact of future conditions similar to those that led to the doubling of the price differentials across the line in 2012. SWIP North will provide significant insurance value to mitigate the impact of high-cost events such as the gas supply issues due to the Aliso Canyon leakage or the loss of significant north-to-south transfer capability. NTTG, WestConnect, and CAISO will benefit from the insurance value provided by SWIP North, although this value has not been quantified in this report.
- *Reliability Benefits*: The addition of the 500 kV SWIP North line in northern Nevada (WestConnect) and southern Idaho (NTTG) will provide reliability benefits by reinforcing the local networks. By shifting flows off of existing lines, SWIP North will reduce the potential for reliability violations and the need for future reliability upgrades as the system load increases over time.
- *Increased Wheeling Revenues*: SWIP North offers opportunities for utilities with transmission rights at Midpoint to increase wheeling revenues associated with transfers out of and across their transmission systems. Based on current charges for annual point-

to-point transmission service on PacifiCorp's system, a 1,000 MW of "out" or "through-and-out" transmission reservations sold by NTTG or WestConnect utilities would generate incremental wheeling revenues of approximately $28 million per year.

I. Project Description

The Southwest Intertie Project-North (SWIP North) is a planned 275 mile 500 kV alternating current (AC) transmission line from the Midpoint substation in southern Idaho to the Robinson Summit substation in central Nevada. It is being developed by an LS Power subsidiary, Great Basin Transmission, LLC (GBT). In combination with the recently completed One Nevada Transmission Line (ON Line) from Harry Allen to Robinson Summit and the California ISO (CAISO)-approved Harry Allen to Eldorado (DesertLink) Line (with a 2020 in-service date), SWIP North will create a major new interregional transmission path from Midpoint to Harry Allen, which spans the Northern Tier Transmission Group (NTTG), WestConnect, and CAISO. Based on studies undertaken for the Western Electricity Coordinating Council's (WECC) path rating process, GBT anticipates that the new transmission path will have a bi-directional rating of at least 1,700 megawatts (MW).

Figure 1: Map of Proposed SWIP North Line



Source: LS Power.

SWIP North creates a parallel transmission path to the existing constrained paths—the California-Oregon Interface (COI) and North-of-Oregon Border Inter-tie (NOB)—that interconnects the northwestern portion of WECC with CAISO and the Southwest. SWIP North offers interconnection opportunities with PacifiCorp's planned Gateway West project, which collectively would provide a major new transmission path between the low-cost-wind-generation areas in Wyoming and markets in California, Nevada, and Arizona.

Based on an existing agreement with NV Energy (related to the ON Line), 700 MW of this new transmission path, from Midpoint to Harry Allen, will be contractually owned by NV Energy, assuming a final path rating of 1,700 MW. The remaining 1,000 MW transfer capability created between Idaho and southern Nevada, CAISO, and Arizona is owned by GBT and is currently unassigned.[1]

II. Benefits of SWIP North

The addition of SWIP North results in benefits to the three regions participating in the Interregional Transmission Planning (ITP) process: (1) Northern Tier Transmission Group (NTTG), (2) CAISO, and (3) WestConnect. This report summarizes our preliminary analysis of the benefits that SWIP North is expected to provide across these regions. This summary of benefits should serve as a starting point for the three regions planning efforts as they consider this project in their regional and interregional planning processes.

A. Congestion Relief on COI, Path 26, and Path 15

SWIP North provides a parallel path for flows across the highly utilized California-Oregon Interface (referred to as Path 66) and thus will provide congestion relief across this path. WECC power flow studies show that the addition of SWIP North provides approximately 300 MW of congestion relief on COI.[2] This is a substantial finding considering that the CAISO's annual congestion charges along the California-Oregon corridor (including COI and NOB) have ranged from $60 million to $150 million per year for 2012 to 2014 and other balancing areas along the corridor likely incurred additional congestion-related costs.[3]

Currently, based on the existing market simulation approach utilized by the CAISO, the economic analysis, contained in the 2015–16 CAISO Transmission Plan, does not capture the real-world COI congestion, and substantially understates the congestion relief provided by SWIP North and thus undervalues the benefit of adding the project to the Western transmission grid. Specifically, the 2015–16 CAISO Transmission Plan analysis projected COI congestion charges to be $0.7 million in 2020 and $0.3 million in 2025—a stark contrast with actual congestion costs in the $100 million per year range.[4] Thus, the simulated results present a substantial understatement of congestion costs. Such understated results are likely due to the modeling assumptions that reflect only normalized system conditions (weather, hydro, and fuel prices),

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1 If the path rating exceeds 1,700 MW, the capacity rights will be allocated between NV Energy and GBT according to an agreed upon formula.

2 The COI congestion relief of approximately 300 MW is based on the preliminary WECC path rating study of SWIP North.

3 CAISO, 2014 Annual Report on Market Issues & Performance, Department of Market Monitoring, p. 145.

4 CAISO, 2015–2016 Transmission Plan, Board Approved, March 28, 2016, p. 297.

without adequately considering actual transmission and generation outages and the "frictions" encountered by market participants when scheduling power across the various paths between balancing areas. The stark discrepancy between actual historical and simulated congestion shows that more realistic simulation of the transmission congestion on the CAISO-WECC system will be needed to accurately capture the value of SWIP North. Both LS Power and the Transmission Agency of Northern California (TANC) have previously highlighted these issues to CAISO through comments on the CAISO's transmission planning process and results.[5, 6]

Despite the stark discrepancy in congestion costs, the same 2015–16 CAISO transmission planning analysis of SWIP North found that the project reduces the number of congested hours on COI by 39%.[7] In addition, the same analysis shows that SWIP North reduces the duration of congestion on Path 15 by 5% and Path 26 by 11%.[8] If we apply this aspect of the CAISO's analysis and apply these reductions to the actual historical COI congestion charges, we find that the project may reduce annual congestion charges by $23 million to $55 million per year. This reduction of congestion across COI will decrease production costs, reduce purchase costs, and increase sales revenues—benefits that likely would accrue primarily in NTTG and CAISO.

The creation of a new north-south path between the northwestern and southwestern portions of the WECC provides an opportunity for actively shifting power flows away from COI to further reduce congestion. The additional shifts of power flows could be achieved by means of topology control (*i.e.*, line switching or substation reconfiguration) and/or the installation of power flow control devices (such as phase shifters).

B. Energy Market Value

The new path created by SWIP North will result in energy market benefits for NTTG, WestConnect, and CAISO by allowing for a more efficient dispatch of generation. To estimate the potential energy market value of SWIP North, we first reviewed historical energy market prices on each side of the new path created by SWIP North and estimated the resulting hourly

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5 "We recommend that CAISO investigate the discrepancies between historical congestion and congestion identified in the economic study and make adjustments to its economic study model, as needed, to benchmark "projected" vs "actual" congestion. The studies should be conducted to accurately quantify congestion in future years, and study of the need for transmission solutions to address congestion issues should be based on this updated projection of intertie congestion." Arora, Sandeep, CAISO 2015/16 TPP: Stakeholder Comments - Nov 16, 2015 Meeting, December 1, 2015.

6 "TANC's primary comment/issue is that the California-Oregon Intertie (COI) and/or full system is not being modeled to reflect the realities that continue to occur and are likely to continue on the high-voltage grid in the evolving marketplace." Transmission Agency of Northern California, TANC Comments on the CAISO's Draft 2015–2016 Transmission Plan, http://www.caiso.com/Documents/TANCCommentsDraft20152016TransmissionPlan.pdf

7 CAISO, 2015–2016 Transmission Plan, Board Approved, March 28, 2016, p. 315.

8 CAISO, 2015–2016 Transmission Plan, Board Approved, March 28, 2016, p. 315.

price difference. The absolute hourly value of this historical price difference provides a "book-end" estimate of the potential region-wide production cost savings due to SWIP North.[9]

As proxies for the locational prices at each end of the new path created by SWIP North, we have identified trading hubs and pricing nodes that are indicative of the wholesale energy prices expected at the northern and southern end of the newly-created path. At the northern end, we use forward prices at the California-Oregon Border (COB) trading hub and CAISO locational marginal prices (LMPs) at the CAISO's Malin pricing node as proxies.[10] We find these prices to be reasonable proxies for the northern end of the project because they are geographically closest to the north end of the path and there is limited congestion between COB and southern Idaho (the actual SWIP North's northern terminus), which means there should not be a large price differential between SWIP North and COB. At the southern end, we use the Mead trading hub and the CAISO's Eldorado pricing node. Eldorado is the southern terminus of the 500 kV Desert Link line that is currently planned to be in service by 2020, which will directly interconnect with SWIP North via the ON Line. Thus, the logical southern market pricing point to represent the delivery point of energy through the new transmission path created the SWIP North is at Eldorado; and the Mead trading hub is directly connected to Eldorado by a 500 kV line.[11]

The analysis of historical CAISO hourly real-time LMPs at Malin and Eldorado shows that the absolute value of the hourly price differential between the two pricing points on either end of this transmission path averaged $7.45 per megawatt-hour (MWh) over the 2010 to 2015 period.[12] When applied to the 1,000 MW portion of the path created by SWIP North, the energy market value associated with this path translates to an annual average value of $65 million per year, with a range between $40 million to $130 million for individual historical years since 2010.[13] Table 1

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9 For example, if energy prices at the northern end of the line are $40/MWh (consistent with the marginal production cost in the region north of the line) and energy prices are $50/MWh at the southern end of the line (consistent with marginal production costs in that region), transferring an additional 1 MW of energy from the north to the south would reduce system-wide production cost by $10 in each hour.

10 We analyzed LMPs at Malin for consistency with the COB trading hub prices because the COB trading hub "comprises the Captain Jack and Malin substations on the AC transmission system between Oregon and California." See: https://www.platts.com/IM.Platts.Content/MethodologyReferences/MethodologySpecs/na_power_method.pdf

11 See: http://www.caiso.com/Documents/PacifiCorpTransmissionSystemMap-PathRatings.pdf

12 Brattle analysis of CAISO average hourly real-time LMPs for 2010 to 2015 from Velocity Suite. For each hour, we calculated the price differential between the nodes and then calculated the absolute value of the differentials to capture the value of both north-to-south and south-to-north flows.

13 Although the addition of SWIP North will add an estimated 1,700 MW or more of transfer capability along the line, we conservatively estimate the energy market value for just the 1,000 MW of incremental capacity added along the ON Line. The addition of a new path and the combined

Continued on next page

shows a summary of the annual averages of LMPs, price differences, absolute price differences, and associated energy value of SWIP North.

Table 1: Eldorado-Malin Annual Real-Time Price Differences and Energy Value

Year	Eldorado Average Price ($/MWh)	Malin Average Price ($/MWh)	Eldorado Average Premium above Malin ($/MWh)	Average Absolute Difference ($/MWh)	Absolute Annual Difference ($/MW-year)
2010	$39.58	$36.57	$3.01	$4.95	$43,000
2011	$29.90	$27.06	$2.85	$4.48	$39,000
2012	$25.32	$22.15	$3.17	$14.45	$127,000
2013	$38.61	$35.74	$2.86	$8.17	$72,000
2014	$41.98	$40.29	$1.69	$6.97	$61,000
2015	$29.90	$31.25	-$1.34	$5.68	$50,000
6-yr Average	$34.22	$32.18	$2.04	$7.45	$65,000

Sources: Velocity Suite, ABB Inc.

Real-time LMPs provide the most realistic representation of the incremental impact that the added transmission will have on the energy market and production costs. This is because real-time hourly prices reflect the actual marginal cost of energy at the time it is produced under real-time conditions. These conditions reflect the added costs incurred during unexpected system conditions and disturbances. In contrast, the day-ahead and monthly forward prices are based on forecasts of these conditions, not the actual conditions, and thus will miss short-term fluctuations and associated high-priced time periods that reflect the true value of increasing transmission capacity. For this reason, the absolute price differentials between the points on either end of the transmission path created by SWIP North are smaller when calculated with day-ahead prices or monthly forward prices from various sources. Table 2 below summarizes the 2010–2015 average of the absolute price differences ($/MWh) and implied energy market values ($/MW-year) based on real-time prices, hourly day-ahead prices, day-ahead forward prices, the monthly average of day-ahead forward prices, and monthly forward prices. As the table shows, forward prices capture a portion of the real-time value that can be provided by the new transmission path. The energy market value based on day-ahead prices is roughly 30% lower than that based on real-time prices, while the value based on monthly forward prices is roughly 50% lower.

Continued from previous page

capacity along that path are likely to have a greater impact, though likely offset by the inability to provide the full value of the price differentials.

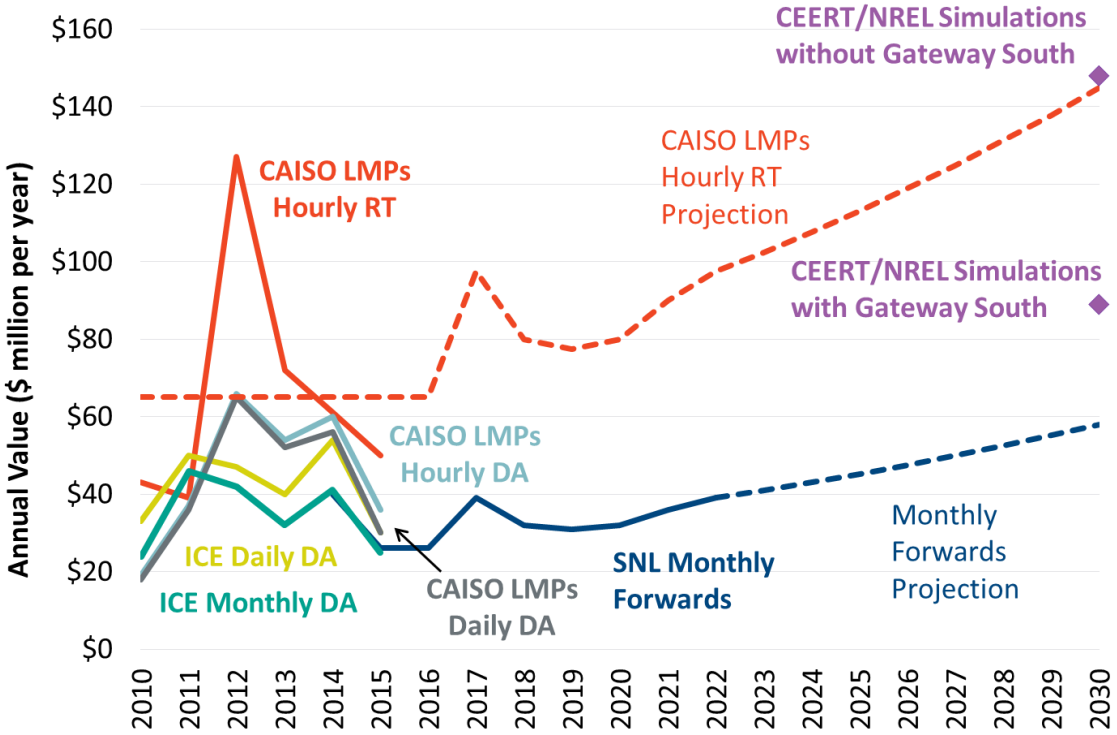
Table 2: Analysis of Price Differentials across SWIP North Based on Real-Time and Forward Prices

	Energy Price Source	Period	North Node	South Node	Absolute Annual Difference ($/MWh)	Absolute Annual Difference ($/MW-year)
1	CAISO LMPs Hourly RT	2010 - 2015	Malin	Eldorado	$7.45	$65,000
2	CAISO LMPs Hourly DA	2010 - 2015	Malin	Eldorado	$5.17	$45,000
3	CAISO LMPs Daily DA	2010 - 2015	Malin	Eldorado	$4.87	$43,000
4	ICE Daily DA	2010 - 2015	COB	Mead	$4.84	$42,000
5	ICE Monthly DA	2010 - 2015	COB	Mead	$3.99	$35,000
6	SNL Monthly Forwards	2014 - 2016	COB	Mead	$3.49	$31,000
7	SNL Monthly Forwards	2017 - 2022	COB	Mead	$3.96	$35,000

Sources and Notes: Velocity Suite, ABB Inc. and SNL Financial LC.

Figure 2 below shows various estimates of the annual energy value and production cost savings of the transmission path created by SWIP North based on: (1) the different sources of historical prices included in the table above (solid lines); (2) a projection of the real-time energy value (as a book-end estimate of production cost savings) based on extrapolating the historical real-time energy value using the trend of monthly forward market prices (dashed lines); and (3) production cost savings based on market simulations for 2030 conducted by the Center for Energy Efficiency and Renewable Technologies (CEERT) and the National Renewable Energy Laboratory (NREL) (marked with a purple diamond and discussed further below).

Figure 2: Historical and Projected Annual Energy Market Value and Estimated Production Cost Savings of SWIP North



Sources and Notes: Velocity Suite, ABB Inc. (CAISO LMPs), SNL Financial LC (ICE and Monthly Forwards), and Caldwell, James and Liz Anthony, Low Carbon Grid Study: SWIP North Economic Benefits, March 2016

(CEERT/NREL Simulations). Monthly Forwards Projection is calculated using the 2018–2022 compounded annual growth rate. CAISO LMPs Hourly RT Projection is calculated as the 2010–2015 average Hourly RT Value projected forward each year based on the Monthly Forwards annual growth rate. The CEERT/NREL Simulations values represent WECC-wide production cost savings and include Gateway West in both cases. The production cost savings have been escalated from the reported values in 2014 dollars to 2030 dollars.

The current monthly forward prices available through 2022 (solid blue line) indicate that the price differential across the path created by SWIP North is trending upwards. This trend is likely associated with projected increases in natural gas prices and a continued trend towards increased interregional power flows. For estimating the future real-time energy market value, first we projected the monthly forward prices through 2030 (dashed blue line) by increasing the 2022 forwards with the average historical annual increases between 2018 and 2022. We then projected the real-time energy market value through 2030 (red dashed line) by growing the 2010–2015 historical average real-time energy market value of $65 million per year with the growth rate of the monthly forwards prices. As shown, these projections result in the estimated real-time energy market value increasing over time to approximately $110 million in 2025 and $145 million in 2030. These book-end estimates show that SWIP North must be expected to offer significant energy market value by providing the ability to purchase lower cost power and capture production cost savings for NTTG, CAISO, and WestConnect. These estimated bookends for the project's production cost savings significantly exceed the benefits captured in the market simulations the CAISO conducted to date.

Also included in Figure 2 are the estimated 2030 production cost savings associated with SWIP North based on recent CEERT/NREL market simulation analyses (shown as purple diamonds).[14] The CEERT/NREL simulations analyzed the 2030 value of SWIP North under two cases, one assuming that Gateway South is not built by 2030 and another with Gateway South in service by 2030.[15] The CEERT/NREL market simulations reflect significant renewable capacity additions similar to the Target Conventional case in the Low Carbon Grid Study (LCGS), which achieves 50% greenhouse gas (GHG) emissions reductions from the California electric sector by 2030 through the addition of renewable capacity and increases in energy efficiency.[16]

These CEERT/NREL analyses found that the annual production cost savings in 2030 associated with SWIP North are in the range of approximately $90 million (with Gateway South) and $150

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[14] For details on the CEERT/NREL analysis, see: Caldwell, James and Liz Anthony, Low Carbon Grid Study: SWIP North Economic Benefits, March 2016. NREL completed this analysis for the purpose of valuing SWIP North utilizing many of the same assumptions as those made in the Low Carbon Grid Study released in February 2016.

[15] Both cases assume Gateway West is built.

[16] The Target Conventional scenario reaches 56% renewable penetration in California and 16% in the rest of WECC. For a detailed description of the Target Conventional scenario in the Low Carbon Grid Study, see: Brinkman, Jorgenson, Ehlen, Caldwell, Low Carbon Grid Study: Analysis of a 50% Emission Reduction in California, NREL/TP-6A20-64884, January 2016, p. 3.

million (without Gateway South).[17] The CEERT/NREL production cost simulation results do not reflect conditions with transmission outages or real-time load and generation uncertainties and, thus, they can be thought of as hourly day-ahead prices and market conditions. Actual production cost savings under the market conditions modeled by CEERT/NREL will be higher than the estimated savings due to the normalized and fully-deterministic nature of the simulations.[18] Thus, we expect the energy market value of SWIP North to be higher than what was captured in the CEERT/NREL analysis and likely higher than the historical real-time value extrapolated to 2030.

We also reviewed the utilization of SWIP North in the Phase II results of the LCGS.[19] The LCGS includes additional scenarios that demonstrate the projected utilization and value of SWIP North in 2030 across market conditions not captured in the most recent CEERT/NREL simulations. The results from those LCGS scenarios provide evidence of the future value of the project by showing that the path created by SWIP North is heavily utilized in the simulated renewables-rich future.[20] Figure 3 below shows flow duration curves across SWIP North for five different scenarios modeled in the LCGS. As seen in these flow duration curves, SWIP North is fully loaded at 2,000 MW (in either direction) for 25% to 31% of hours under the different scenarios.[21] In addition, the curves show that SWIP North is utilized in the north-to-south direction for delivering wind and hydro resources from regions in NTTG south to CAISO and WestConnect utilities, and is almost equally utilized in the south-to-north direction carrying excess generation from solar generation from CAISO and WestConnect regions to NTTG utilities, depending on

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[17] These values represent the nominal dollar equivalent to the CEERT/NREL values, which were reported in 2014 dollars.

[18] A detailed discussion of these limitations can be found in section VI.A of Chang, Pfeifenberger, and Hagerty, The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments, WIRES and The Brattle Group, July 2013.

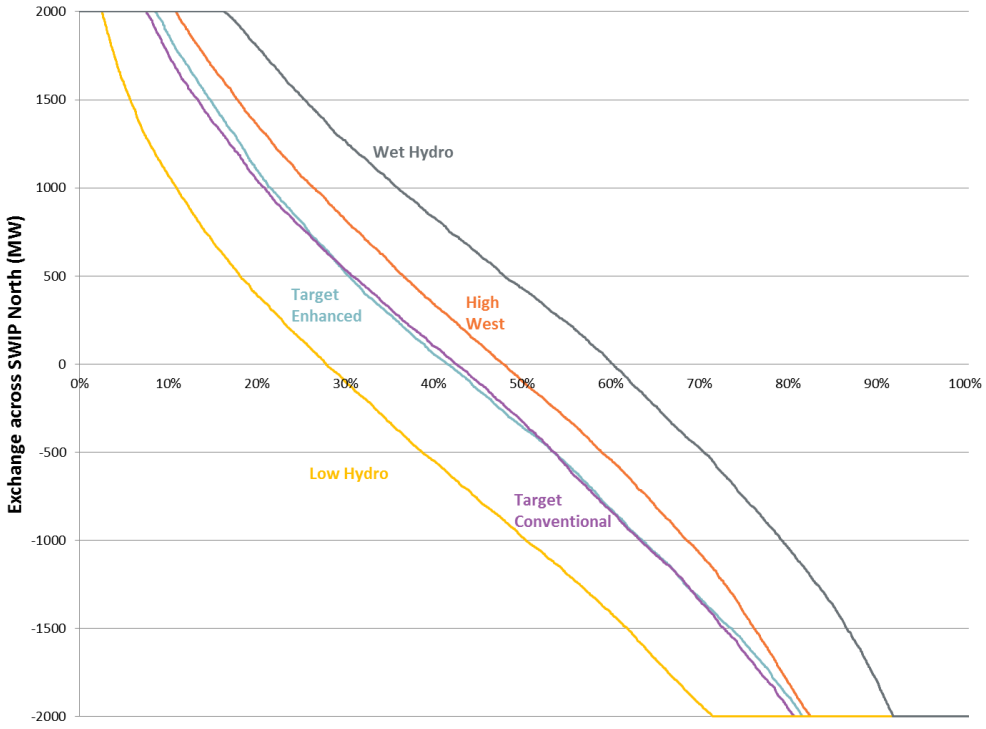
[19] Brinkman, Jorgenson, Ehlen, Caldwell, Low Carbon Grid Study: Analysis of a 50% Emission Reduction in California, NREL/TP-6A20-64884, January 2016.

[20] The LCGS modeled several 2030 scenarios that achieve 50% GHG emissions reductions in California. In 2030 while these scenarios for renewable additions and GHG emissions reductions across WECC by 2030 are more aggressive than any specific actions currently planned, it is likely that the WECC region will continue to move closer to the scenarios modeled in the LCGS due to the continued GHG emissions reduction in California to achieve 40% GHG emissions reductions in 2030 (relative to 1990 levels) and the likely ultimate implementation of the EPA's Clean Power Plan or other clean-energy regulations in the other western states, such as Oregon's recent legislation implementing a 50% renewable energy target. For details on the LCGS assumptions, see: Brinkman, Jorgenson, Ehlen, Caldwell, Low Carbon Grid Study: Analysis of a 50% Emission Reduction in California, NREL/TP-6A20-64884, January 2016.

[21] Data provided by NREL from Brinkman, Jorgenson, Ehlen, Caldwell, Low Carbon Grid Study: Analysis of a 50% Emission Reduction in California, NREL/TP-6A20-64884, January 2016. The LCGS assumed SWIP North capacity of 2,000 MW, which is consistent with the range anticipated by GBT based on the preliminary WECC path rating study.

the scenario. Across all hours, the average utilization in the LCGS scenarios is approximately 60%.

Figure 3: SWIP North Flow Duration Curves in LCGS Scenarios



Source and Notes: Data provided by NREL from Brinkman, Jorgenson, Ehlen, Caldwell, Low Carbon Grid Study: Analysis of a 50% Emission Reduction in California, NREL/TP-6A20-64884, January 2016. Positive values indicate north-to-south flows.

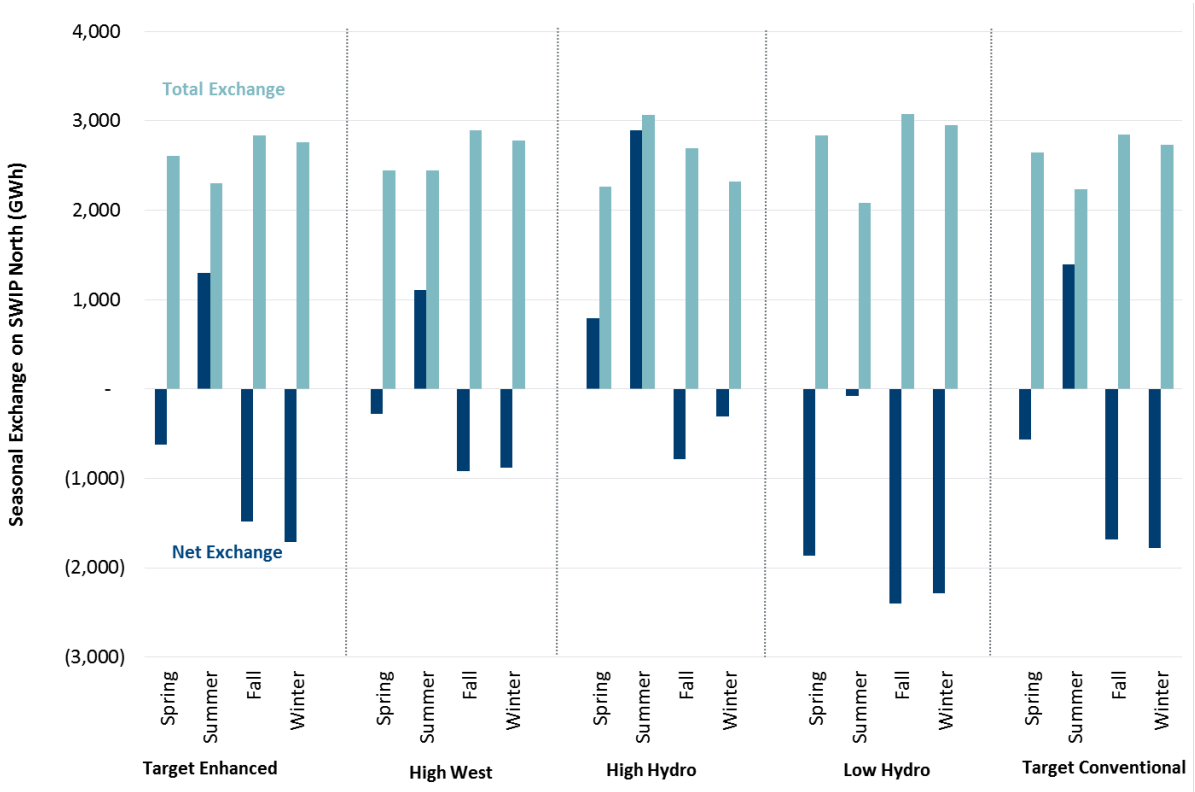
SWIP North's utilization will reduce production costs throughout the West (as shown in the NREL simulations in Figure 2 above) as well as relieve solar curtailments in the southwest and reduce the capital costs of installing additional renewable capacity to meet RPS and GHG reduction goals. These additional benefits have not been quantified in this report.

Figure 4 below shows the total exchange and the net exchange across SWIP North on a seasonal basis for several LCGS scenarios. The LCGS analysis finds that SWIP North's total utilization is similar across multiple scenarios, ranging from 10,300 GWh during high-hydro years to 10,900 GWh during low-hydro years.[22] The NREL LCGS study shows that SWIP North is utilized differently depending on the future capacity build out and power market conditions, especially hydro conditions. For example, while daily variations and system ramps remain very similar, the difference in the annual exchange between high- and low-hydro years is estimated to be 9,200 GWh: during high-hydro years there is an estimated annual net transfer across SWIP North of 2,600 GWh north-to-south, while during low-hydro years the estimated net transfer is 6,600

[22] Data provided by NREL from Brinkman, Jorgenson, Ehlen, Caldwell, Low Carbon Grid Study: Analysis of a 50% Emission Reduction in California, NREL/TP-6A20-64884, January 2016.

GWh south-to-north. These results reinforce the expectation that the path created by SWIP North can provide value to the system across a wide range of future scenarios with different portfolios of renewable generation and different hydro conditions.

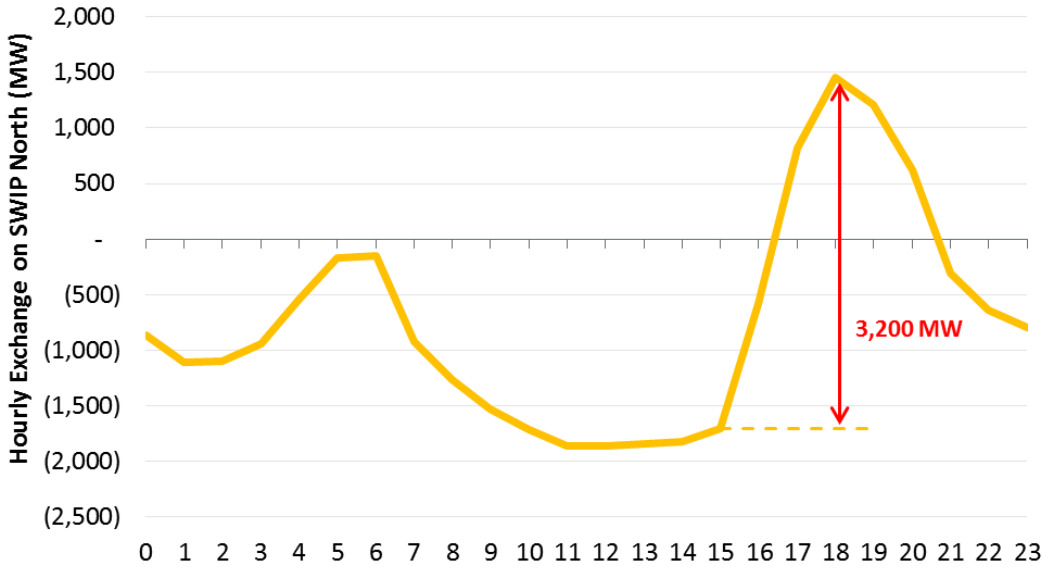
Figure 4: Seasonal Net and Gross Exchange Across SWIP North



Sources: Data provided by NREL from Brinkman, Jorgenson, Ehlen, Caldwell, Low Carbon Grid Study: Analysis of a 50% Emission Reduction in California, NREL/TP-6A20-64884, January 2016. Positive values indicate north-to-south flows.

Figure 5 shows that an important future benefit of SWIP North based on the NREL LCGS results is its ability to provide access to over 3,000 MW of daily, 3-hour ramping capability during critical winter and spring days. The provision of this ramping capability allows SWIP North to support CAISO's daily transitions from high solar generation at 3 p.m. in the afternoon (with 1,700 MW of south-to-north flow) to meeting the evening 6 p.m. peak load after sunset (with 1,500 MW of north-to-south flow). The ramping capability provided by the new path created by SWIP North will reduce the need for, and the costs of, flexible capacity procurement in the CAISO, which will provide benefits in addition to those estimated above based on historical market prices or the CEERT/NREL simulations.

Figure 5: Average Daily Winter Utilization of SWIP North in Target Enhanced Scenario



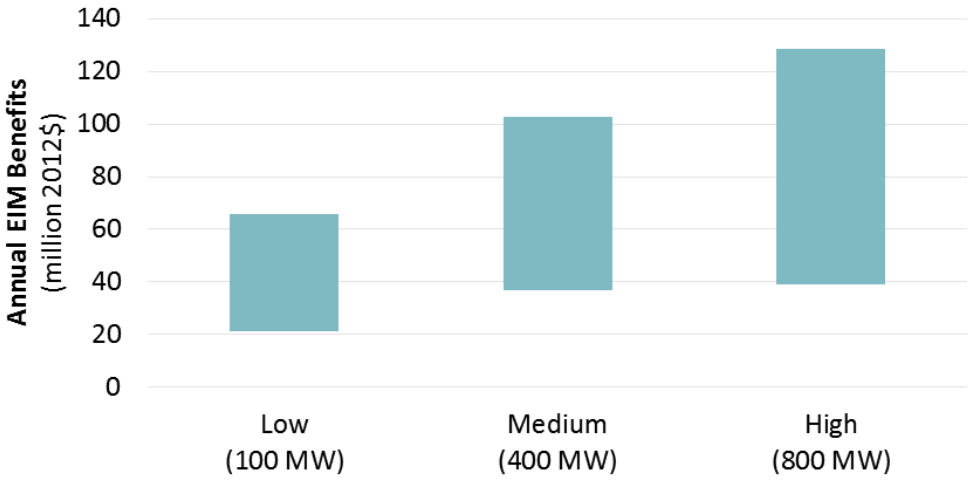
Source: Data provided by NREL from Brinkman, Jorgenson, Ehlen, Caldwell, Low Carbon Grid Study: Analysis of a 50% Emission Reduction in California, NREL/TP-6A20-64884, January 2016. Positive values indicate north-to-south flows

C. Benefits Related to EIM and CAISO-PacifiCorp Integration

The 2013 analysis of the Energy Imbalance Market (EIM) between the CAISO and PacifiCorp found that the benefits of the EIM depend on the transfer capability between the two systems. The addition of SWIP North, which creates at least 1,000 MW of additional transfer capability between the PacifiCorp and CAISO balancing areas, will consequently increase EIM benefits. For example, Figure 6 below shows that the 2013 analysis of EIM benefits found that increasing transfer capability from 400 MW to 800 MW increases annual benefits by up to $26 million per year.[23]

[23] E3, PacifiCorp-ISO Energy Imbalance Market Benefits, March 13, 2013, Table 2, p. 9.

Figure 6: Impact of CAISO-PAC Transfer Capability on Annual EIM Benefits



Source: E3, PacifiCorp-ISO Energy Imbalance Market Benefits, March 13, 2013, Table 2, p. 9.

In addition to these EIM benefits, SWIP North would very likely provide significantly higher benefits if PacifiCorp and CAISO succeeded in their efforts to create a regional market. Based on the ISO-PacifiCorp integration study, the transfer capability between the two regions is currently projected to be limited to 776 MW from CAISO to PacifiCorp and to 982 MW from PacifiCorp to CAISO.[24] SWIP North would create at least an additional 1,000 MW of transfer capability between the two regions and increase the integration benefits by reducing dispatch costs, allowing greater reserve sharing, and avoid generation capacity costs.

Analysis of the benefits of APS and NV Energy joining the EIM do not specifically highlight limitations due to transfer capability between their respective systems.[25] However, the additional path between PacifiCorp, NV Energy, and CAISO will likely bring additional EIM-related benefits to both existing and future EIM participants.

D. Load Diversity Benefits and Capacity Cost Savings

The new transmission path created by SWIP North, ON Line, and Harry Allen to Eldorado offers potential load diversity benefits to NTTG, WestConnect, and CAISO. Although it has been determined that the line will shift approximately 300 MW of power flows away from the congested COI path, it has not been determined the extent to which SWIP North will increase the transfer capability into CAISO. Nevertheless, the line interconnects regions with divergent load patterns that would make it possible to reduce resources adequacy needs.

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[24] E3, Regional Coordination in the West: Benefits of PacifiCorp and California ISO Integration, Technical Appendix, October 2015, p. 2.

[25] See EIM benefit studies posted here: https://www.caiso.com/informed/Pages/EIMOverview/Default.aspx

We analyzed the potential for balancing areas on either end of SWIP North to share resource adequacy capacity due to differences in the timing of peak load. We specifically reviewed the load diversity savings potential between the CAISO and PacifiCorp, CAISO and Idaho Power, and between a broader pool of balancing areas including CAISO, PacifiCorp, Idaho Power, NV Energy, LA Department of Water & Power (LADWP), and Salt River Project (SRP). Our analysis finds that the regional coincident peak tends to be closely aligned with the CAISO peak in most years, such that most of the reduced resource adequacy requirement due to the shift from each entity's own non-coincident peak to the coincident peak shared with CAISO is realized by the utilities in NTTG and WestConnect.

Our analysis of the potential capacity savings for PacifiCorp due to the new transmission path provided by SWIP North finds that capacity savings are likely beyond the existing 776 MW contract path assumed in the PacifiCorp-ISO integration study.[26] The additional transfer capability on the path created by SWIP North will allow PacifiCorp to reduce its reserve margin requirements by an additional 390 MW in 2020 and 450 MW in 2030. We estimate the potential capital cost savings of avoided capacity costs for PacifiCorp to be $15 million in 2020 and $45 million in 2030, assuming capacity costs of $38/kW-year can be avoided in 2020 and higher capacity costs of $100/kW-year can be avoided in 2030.[27]

We analyzed the potential for CAISO and Idaho Power to reduce resource adequacy needs due to load diversity since the two balancing areas are not directly interconnected today. Our analysis finds that due to the differences between their coincident and non-coincident peaks, the addition of SWIP North would allow for the sharing of 600 MW of capacity between CAISO and Idaho Power. The associated benefit, which would mostly accrue to Idaho Power, has not been quantified in this study. Figure 7 below shows how the combined non-coincident, or standalone, peaks are greater than the coincident peak across the combined footprint. While there is currently significant regional transfer capacity through balancing areas that are physically located between CAISO and Idaho Power, the addition of SWIP North will provide the first direct connection between them, which should facilitate capturing these benefits.

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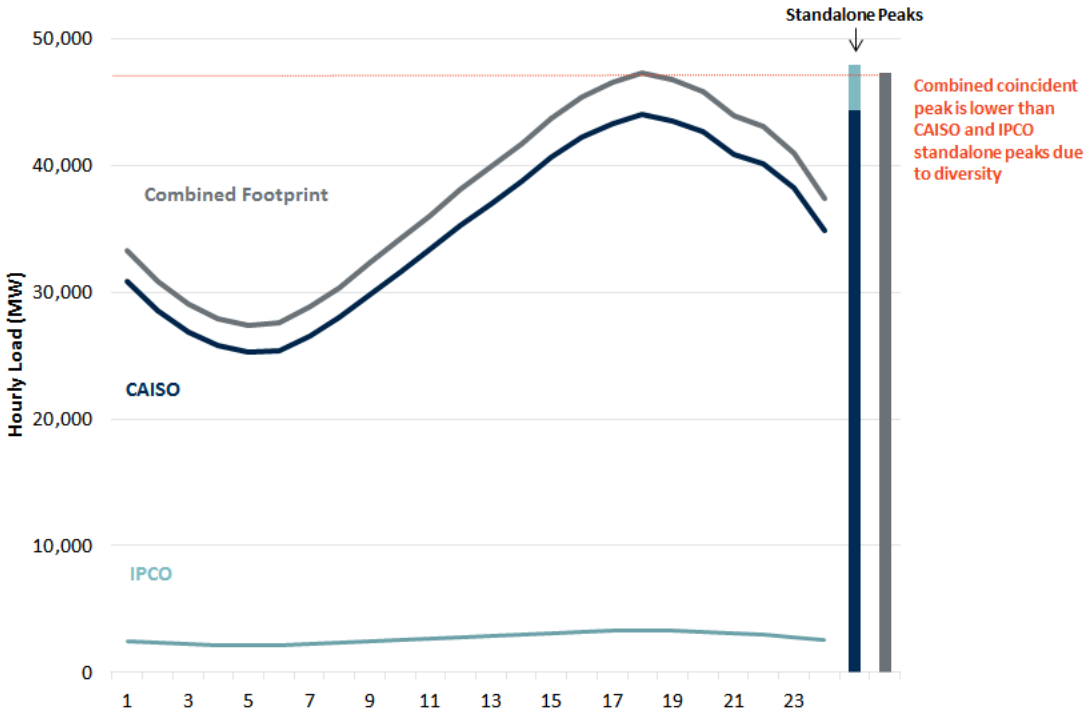
[26] "For PacifiCorp, potential capacity cost savings are limited by transmission constraints, assumed here to be 776 MW." E3, Regional Coordination in the West: Benefits of PacifiCorp and California ISO Integration, October 2015, p. 20.

[27] We assumed a 2020 capacity value of $38/kW-year based on recent resource adequacy contracts in California as reported in the E3 PAC Integration study. For 2030, we applied an avoided cost of capacity of $100/kW-year, as a conservatively low estimate of the net cost of new entry for a gas combined-cycle unit. E3, "Regional Coordination in the West: Benefits of PacifiCorp and California ISO Integration," Technical Appendix October 2015, p. 12.

Figure 7: Potential Capacity Savings between CAISO and Idaho Power



Source: Brattle analysis of Velocity Suite, ABB load data on July 31, 2014.

Similar load diversity analysis of a wider footprint around SWIP North that includes CAISO, PacifiCorp, Idaho Power, NV Energy, LADWP, and SRP finds that there is potential for capacity savings through 2,900 MW of load diversity benefit across these balancing areas. The addition of SWIP North has the potential to ease sharing and increase transfer capabilities between entities at the southern end of the new path created by SWIP North and Desert Link (CAISO, LADWP, SRP), with those entities with access at the northern end of SWIP North (Idaho Power and PacifiCorp). This transfer capability will facilitate the realization of load diversity benefits for NV Energy who has access to multiple points on this path. These benefits have not been quantified in this study.

In addition to load diversity benefits, the additional transfer capability created by SWIP North between NTTG and WestConnect may reduce generation capacity costs by either: (1) providing access to temporary amounts of excess generation in the other region; or (2) allowing more new generation capacity to be built in the lowest-cost locations of the combined footprint. For example, the capital cost for new combined-cycle plants in Arizona are estimated to be 18% lower than in PacifiCorp.[28] To the extent SWIP North creates additional simultaneous transfer

[28] Combined-cycle capital cost estimates of $988/kW for APS and $1,202/kW for PacifiCorp are based on values included in each utility's Integrated Resource Plan analysis. E3, Capital Cost Review of Power Generation Technologies: Recommendations for WECC's 10- and 20-Year Studies. March 2014, p. 18. Available at:

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capability into the CAISO footprint, such generation capacity cost savings would benefit the CAISO.

E. INSURANCE VALUE

Transmission investments offer "insurance value" by providing additional flexibility that allows the grid to respond more cost-effectively to both short-term operational and long-term planning uncertainties. The addition of SWIP North will mitigate the adverse impacts of both short-term extreme events and long-term challenges on electricity market participants and retail customer rates. More specifically, transmission projects provide such insurance value with respect to two types of uncertainties:[29]

1. Short-term uncertainties, such as extreme (but temporary) contingencies, constrained fuel supplies, and weather conditions that can lead to spikes in load, hydro variations, renewable generation output, or generation and transmission outages.
2. Long-term uncertainties, such as 5–10 year changes in fuel prices, technology costs, environmental regulations, and/or public policy goals that, in the absence of the transmission project, would impose substantial costs on market participants and retail customers.

For example, we found in our analysis of market prices across SWIP North that applying the absolute real-time price difference between Malin and Eldorado from 2010 through 2015 to a 1,000 MW of additional transfer capability yields a 6-year average annual value of $65 million per year. However, this average value is substantially influenced by the conditions in a single year: in 2012, the value of 1,000 MW transfers was $127 million, while the average for the other five years was only $53 million. Thus, more challenging market conditions resulted in benefits that in one year were significantly more than twice the "normal" $53 million 5-year average, yielding a six-year average that was 23% above the five-year average.

CAISO has previously studied the insurance value of similar transmission projects. For example, its 2004 study of the Palo Verde to Devers No. 2 (PVD2) line illustrated this point.[30] The

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https://www.wecc.biz/Reliability/2014_TEPPC_Generation_CapCost_Report_E3.pdf

[29] For a broader discussion of the insurance value of transmission, see: Pfeifenberger, Chang, and Sheilendranath, "Toward More Effective Transmission Planning: Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid, Prepared for WIRES, April 2015. Posted at: http://www.brattle.com/system/publications/pdfs/000/005/154/original/Toward_More_Effective_Transmission_Planning_Addressing_the_Costs_and_Risks_of_an_Insufficiently_Flexible_Electricity_Grid.pdf?1429801687

[30] See Pfeifenberger, Chang, and Sheilendranath, "Toward More Effective Transmission Planning: Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid, Prepared for WIRES, April 2015, Section III.B and Appendix A. Posted at:

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CAISO's production cost simulations under base-case conditions estimated production cost savings of $55 million per year. When considering savings beyond production cost savings, the total cost savings increased to $100 million per year. However, when considering the probability of infrequent but high-cost events, the probability-weighted average increased by 20% to $120 million per year. This increase in the probability-weighted average greatly understates the substantial cost savings the project was estimated to provide under the most challenging market conditions. The CAISO's study found that, without the proposed line, there was a 10% chance (comparable to once in 10 years) that the annual cost would be at least $300 million (and possibly up to $750 million) higher without PVD2. The high end of this range is associated with a long-term outage of the SONGS nuclear stations, which was considered as an extreme contingency in this 2004 study. This example documents the importance of "insurance value" by showing that under certain circumstances the cost savings offered by a transmission project can exceed "base case" savings estimates by a factor of ten.

A very recent example of unforeseen events in which transmission provides insurance value is the natural gas leakage issues at Aliso Canyon near Los Angeles. The ongoing issues with natural gas leaking from the storage facility may result in limited gas supply in the summer of 2016. Because of such gas supply shortages, there is potential for short-term electricity system operability and reliability issues.[31] In circumstances such as these, additional transmission provides the system with more flexibility to respond to the limited fuel supply availability by relying on a wider range of generation facilities and fuel types.

SWIP North will provide insurance value to protect against the loss of significant transfer capacity on the few existing north-south lines in WECC. A disturbance of this nature could result in very high system costs and large economic losses across the region due to power outages to businesses until the system can be restored. The potential of such events occurring is understood by WECC, which has developed operational schemes to separate the northwestern and southwestern portion of the region in the case of the loss of certain elements of the Pacific Intertie.[32] The additional interregional transmission path could greatly mitigate the potential impact of such an event and avoid the need for significant operational actions to maintain system operation. The impending retirements due to once-through-cooling requirements and the potential retirement of Diablo Canyon are additional near-time examples in which additional transmission infrastructure could help mitigate potentially very high cost outcomes.

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http://www.brattle.com/system/publications/pdfs/000/005/154/original/Toward_More_Effective_Transmission_Planning_Addressing_the_Costs_and_Risks_of_an_Insufficiently_Flexible_Electricity_Grid.pdf?1429801687

31 Colbert, Cathleen, Aliso Canyon Gas Electric Coordination, Issue Paper Stakeholder Call, March 23, 2016. Available at: http://www.caiso.com/Documents/Agenda_Presentation_AlisoCanyonGasElectricCoordination.pdf

32 WECC RAS #18, Major WECC Remedial Action Schemes (RAS), Used in Standard PRC-004-WECC-1, Revised September 19, 2007.

We recommend that, in the context of the interregional planning process, the value of SWIP North be evaluated for a plausible range of such uncertainties to capture at least a portion of the insurance value of the line.

F. Reliability Benefits

The addition of the 500kV SWIP North transmission line will have positive reliability benefits in the area in which the line is located. The transmission system in northern Nevada is based on a network of 345 kV lines that has limited transfer capability. For example, the 345 kV system limits the capability of the existing ON Line to approximately 1,000 MW north-to-south and 600 MW south-to-north.[33] Adding the 500 kV SWIP North line across northern Nevada adds at least 1,000 MW of transfer capability to ON Line, reinforces the local 345 kV network, and increases the reliability of the local system. In addition, shifting flows off of existing 345 kV lines will reduce the potential for reliability violations and the need for reliability upgrades as the system load increases over time.

The new 500 kV intertie and associated increased transmission intertie capacity into the Idaho Power and PacifiCorp systems in the north and the CAISO, LADWP, and SRP systems in the south will provide regional reliability benefits to NTTG, WestConnect, and CAISO members.

The additional transmission capability in southern Idaho and northern Nevada will provide operational flexibility during periods of maintenance on the existing transmission system and generating plants. Taking transmission lines out of service for maintenance often must occur in the spring or fall to avoid creating significant congestion on the system. The addition of the new path will provide greater flexibility in choosing when maintenance can be performed and limiting reliability concerns and cost increases when the maintenance occurs.

G. Increased Wheeling Revenues

Creating a new north-to-south transmission path with at least 1,700 MW transfer capability between Midpoint, Robinson, Harry Allen, and Eldorado offers substantial opportunities for increased electricity trading throughout the West. Utilities with transmission rights at Midpoint (PacifiCorp and Idaho Power) will be able to increase wheeling revenues associated with transfers out of and across their transmission system (*e.g.*, from the Mid-C trading hub to Midpoint) for any transactions (*e.g.*, to Nevada, California, or Arizona) that utilize the new transfer capabilities created by SWIP North.

For example, under PacifiCorp's Open Access Transmission Tariff (OATT) the charge for an annual reservation for point-to-point transmission service is currently $28,472/MW-year.[34] At

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[33] Transfer capability limits on existing lines provided by LS Power.

[34] PacifiCorp, PacifiCorp Transmission Rates, December 1, 2015. Available at: http://www.oasis.oati.com/PPW/PPWdocs/Rate_Table_20151201.pdf

this rate, each 1,000 MW of "out" or "through-and-out" transmission reservations sold by NTTG or WestConnect utilities, including NV Energy on its 700 MW portion of SWIP North, would generate incremental wheeling revenues of $28 million per year. Any such incremental wheeling revenues would be a real and tangible benefit associated with the new trading opportunities created by SWIP North.