UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

The Nevada Hydro Company, Inc.	)	
	)	
v.	)	**Docket No. EL19-81-000**
	)	
California Independent System Operator Corporation	)	
	)	

MOTION FOR LEAVE TO FILE ANSWER AND ANSWER OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION TO MOTION AND REPLY

Dated: September 20, 2019

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The California Independent System Operator Corporation ("CAISO") hereby submits this limited answer to the Motion and Reply filed by The Nevada Hydro Company, Inc. ("Nevada Hydro") on September 5, 2019 ("September 5 Reply").[1] In its September 5 Reply, Nevada Hydro again relies on unsupported assertions and misrepresentations of the CAISO's statements and reliability and economic planning studies to support its Complaint that the CAISO erred in not approving its $2 billion pumped storage project ("LEAPS") in the 2018-2019 transmission planning process.

I. MOTION FOR LEAVE TO FILE ANSWER

Under Rules 212 and 213 of the Commission's Rules of Practice and Procedure,[2] the CAISO respectfully requests waiver of Rule 213(a)(2), 18 C.F.R. § 385.213(a)(2), to the extent necessary to permit it to answer the answer filed by

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[1] The CAISO files this answer pursuant to Rules 212 and 213 of the Commission's Rules of Practice and Procedure, 18 C.F.R. §§ 385.212, 385.213. For the reasons explained below, the CAISO respectfully requests waiver of Rule 213(a)(2), 18 C.F.R. § 385.213(a)(2), to permit it to answer certain comments filed in the proceeding.

[2] 18 C.F.R. §§ 385.212, 385.213.

Nevada Hydro in the proceeding. Good cause for the waiver exists because the answer addresses new assertions and claims misrepresenting the CAISO's statements and study inputs, assumptions, and findings. The CAISO's answer will therefore clarify the record, provide additional information to assist the Commission in the decision-making process, and help to ensure a complete and accurate record in the case.[3]

II. INTRODUCTION AND SUMMARY

Nevada Hydro's pleadings in this proceeding are a case study in goalpost moving and ever-shifting arguments. In its Complaint, Nevada Hydro levied a number of criticisms of the CAISO's reliability and economic transmission planning studies of the LEAPS project. In response, the CAISO rebutted these claims and explained, in considerable detail, how the CAISO studied the LEAPS project and determined, consistent with its tariff and study procedures, that LEAPS did not meet a transmission need for the planning horizon considered in the 2018-2019 transmission planning cycle. In its answer, Nevada Hydro responded with several new arguments, which the CAISO addressed and fully rebutted.

Nevada Hydro now has taken a third bite at the apple, filing another answer replete with new arguments and allegations, and dizzying contortions of the CAISO's previous explanations. Ironically, after strenuously insisting in its

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[3] *See, e.g., Equitrans, L.P.,* 134 FERC ¶ 61,250 at P 6 (2011); *Cal. Indep. Sys. Operator Corp.*, 132 FERC ¶ 61,023 at P 16 (2010); *Xcel Energy Servs., Inc.,* 124 FERC ¶ 61,011 at P 20 (2008).

August 6, 2019 reply ("August 6 Reply") that this proceeding was not about a "differences among experts,"[4] Nevada Hydro performs a complete about-face, now arguing that "genuine issues of material fact" require an evidentiary hearing.[5] Although the CAISO does not relish having to correct the record *again*, given the gravity of Nevada Hydro's allegations, particularly those regarding the CAISO's fulfilment of its North Electric Reliability Corporation ("NERC")-mandated reliability planning functions, it is important that the CAISO respond. As demonstrated below, Nevada Hydro's new batch of arguments fare no better than those it previously raised:

- Nevada Hydro continues to obfuscate and confuse the amount of storage resources available to the CAISO to address potential contingencies in the San Diego area. As Mr. Millar explained, the CAISO's study assumptions specifically stated that capacity from battery resources would be shown as dispatched off in the CAISO's base cases and only dispatched as mitigation *when a reliability concern is identified*. Consistent with this, the CAISO's base cases, which Nevada Hydro purports to have relied on, only showed 40 out of 201 MW of storage resources as dispatched in the San Diego area, representing existing pumped storage assets, with the remaining battery assets dispatched when reliability concerns were identified.

[4] August 6 Reply at 3.

[5] September 5 Reply at 2-8.

- Nevada Hydro's allegation that the 161 MW of battery storage that the CAISO relied on is "non-existent" is spurious. Mr. Millar identifies each individual storage unit that comprises the 161 MW of batteries in the transmission plan, which are either already in service or have a contract with a load-serving entity. The CAISO also identifies the California Public Utilities Commission ("CPUC") process that authorized the procurement of each unit.
- Nevada Hydro unduly limited its analysis of the capacity the CAISO could curtail to relieve transmission overloads in the San Diego area to 915 MW of thermal generation that the CAISO can trip automatically via a remedial action scheme in the Imperial Valley area. But it ignored that the CAISO can also manually curtail a significant additional quantity generation east of the Imperial Valley area to address a contingency.
- Nevada Hydro misrepresents the CAISO's statement it did not ignore congestion in its economic analysis as an admission that it calculated congestion benefits separately from "curtailment" benefits. As the CAISO explained previously, its production cost modeling accounted for all benefits that a project could provide to CAISO ratepayers, including any benefits associated with relieving congestion and reducing generator curtailments. Nevada Hydro continues to either misunderstand or deliberately ignore the nature of the CAISO's production cost modeling in favor of promoting a

conclusory and erroneous assumption that any project, regardless of size, location, cost or other characteristics, that reduces generator curtailments must have a positive cost-benefit ratio.

- Nevada Hydro's claim that the CAISO adopted CPUC planning assumptions without "critical evaluation" is based on a contrived misreading of the CAISO's study plan, which consistent with long-standing CAISO practice, made clear that the CAISO would utilize the CPUC's default scenario regarding modeling generation resources.

Finally, Nevada Hydro, through its own statements, continues to admit that the primary benefits that LEAPS would provide are those associated with functioning as a generation and load asset, not a transmission facility. Once again, Nevada Hydro acknowledges that LEAPS' benefits arise primarily from arbitraging the energy markets, pumping when prices are low and discharging when there is less supply and higher prices. This distinguishes LEAPS from the storage assets in *Western Grid* that the Commission found could be transmission precisely because they would *not* arbitrage the energy markets.[6]

In summary, Nevada Hydro provides no evidence of a meaningful factual dispute that would necessitate a hearing, much less meet its burden of showing,

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[6] *Western Grid,* 130 FERC ¶61.056 at P 46 ("*Western Grid*"); *see also Third-Party Provision of Ancillary Servs; Accounting and Fin. Reporting for New Electric Storage Tech.,* Notice of Inquiry, 135 FERC ¶1,240 at n. 47 (2011) (noting that a storage unit acts like a generator when it arbitrages differences in peak and off-peak energy prices or sells ancillary services).

by a preponderance of evidence that the CAISO has failed to study LEAPS under its transmission planning tariff provisions and applicable procedures.

III. ANSWER

A. The Commission Should Reject Nevada Hydro's Conclusory and Unsupported Claim that the CAISO's 2018-2019 CAISO Transmission Plan Fails to Meet Reliability Needs in the San Diego Area

1. The Batteries the CAISO Considered in the 2018-2019 Transmission Planning Process are not Fictitious and Unavailable as Nevada Hydro Claims

Nevada Hydro states that Mr. Alaywan, in examining the resources available to address potential contingencies in the San Diego area, "relied solely on data that CAISO provided in Table 2.9-1 of the 2018-2019 Transmission Planning Report," which did not show the CAISO dispatching an additional 161 MW of batteries.[7] Nevada Hydro then states that when Mr. Alaywan "reviewed the CAISO's models" they only showed "40 MW of battery storage not 201 MW."[8] Nevada Hydro then claims that the 201 MW of batteries are "fictitious" and not in-service or under contract, and that the transmission plan report does not support the CAISO's claim it has 161 MW of batteries that could "resolve first contingency overloads before they trigger a second contingency."[9]

As an initial matter, the CAISO has never claimed there are 201 MW of batteries in service or procured in the San Diego area. The CAISO stated there

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[7] September 5 Reply at 3.

[8] *Id.* at 4.

[9] *Id.* at 3, 5.

are 201 MW of storage resources in the area, 161 MW of which are batteries.[10] The other 40 MW, which the CAISO modeled and dispatched in the CAISO's base cases, are existing pumped storage units, not batteries – the Lake Hodges Pumped Storage Unit Nos. 1 and 2.[11] Besides ignoring the CAISO's previous explanation regarding the source and treatment of this 40 MW and the clear reference to such pumped storage in the CAISO's transmission planning documents, Nevada Hydro also conveniently ignores the fact that that the Lake Hodges Pumped Storage Units are market resources, not transmission assets. Thus, these pumped storage units provide the same services that LEAPS can provide. It would be unduly discriminatory to treat LEAPS as a transmission asset when it would provide the same services and address the same issues in the area as the market-participating Lake Hodges Pumped Storage Units.

Nevada Hydro's claim that the batteries are "fictitious" likewise is erroneous.[12] As the CAISO previously indicated, all of the batteries the CAISO

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[10] CAISO Answer to Complaint (July 22, 2019), at 42, n. 124; CAISO August 21 Reply at 12.

[11] 2018-2019 Transmission Planning Process Unified Planning Assumptions and Study Plan, at A-24 (Mar. 30, 2018) ("2018-2019 Unified Planning Assumptions"), available at http://www.caiso.com/Documents/Final2018-2019StudyPlan.pdf; Appendix A: System Data to the 2018-2019 CAISO Transmission Plan, at A-25 ("Appendix A"), available at http://www.caiso.com/Documents/AppendixA-BoardApproved2018-2019TransmissionPlan.pdf.

[12] On page 2 of his sur-rebuttal testimony, Mr Alaywan states that Appendices A and B to the 2018-2019 transmission planning report show only 40 MW of batteries and do not show an additional 161 MW of batteries. Exhibit NHI-13 at 2. This statement is wrong on two counts. First, Appendix A to the 2018-2019 CAISO Transmission Plan only lists "Generation" and contains sections dealing with "Existing Generation," "Retired Generation," and "Planned Generation." Appendix A does not list, nor claim to list, batteries. Second, the 40 MW of storage listed in Appendix A is the 40 MW Lake Hodges Pumped Storage Unit; it is not a battery. The CAISO traditionally has included pumped storage in the "Existing Generation" tables as the facilities are essentially generators that also have pumping capability. In contrast, batteries and demand response (existing and forecast) are discussed in Sections 3.8.2 and 3.8.3 of the 2018-2019 Unified Planning Assumptions and in each relevant subsection of Chapter 2 of the 2018-

considered in the 2018-2019 transmission planning process were CPUC-approved and either already in operation or under contract and being developed.[13] They were also discussed in the 2018-2019 Unified Planning Assumptions.[14] In Mr. Millar's sur-rebuttal testimony at pages 3-4,[15] the CAISO identifies the batteries that comprise the 161 MW of batteries referred to in the 2018-2019 CAISO Transmission Plan (77.5 MW of which are already in operation) and provides relevant information regarding them, including the source of procurement as described in the 2018-2019 Unified Planning Assumptions. The batteries clearly are not "fictitious" as Nevada Hydro claims. Thus, Nevada Hydro's claim that there is a general issue of material fact whether the CAISO has access to the batteries is baseless.

Nevada Hydro admits that it relies "solely" on how the how the storage was "modeled" in Table 2.9-1 of the 2018-2019 CAISO Transmission Plan,[16] yet ignores that the modeling in Table 2.9-1 shows a total of 201 MW of installed storage capacity, not 40 MW. Also, the 2018-2019 CAISO Transmission Plan

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2019 CAISO Transmission Plan, along with the discussions of load forecasts and other parameters relevant to the individual planning region being discussed. Nevada Hydro also ignores the plain wording in the transmission plan that the CAISO's "Supply-Side Assumptions," as summarized in Table 2.9-1, included "conventional and renewable generation, and along with energy storage." 2018-2019 CAISO Transmission Plan (March 29, 2019) at 182-183, available at http://www.caiso.com/Documents/ISO_BoardApproved-2018-2019_Transmission_Plan.pdf.

[13] CAISO Answer to Complaint at 33, n. 95.

[14] As discussed in the 2018-2019 Unified Planning Assumptions, storage expressly included (1) already-procured storage under CPUC Decision D.13-10-040 with a 2020 target date and (2) batteries planned to be placed in service in the early 2017 time frame. *See* 2018-2019 Unified Planning Assumptions at 29-30.

[15] Mr. Neil Millar's sur-rebuttal testimony is attached hereto as CAISO Exhibit-5 ("CAISO Exhibit-5").

[16] September 5 Reply at 3, citing Exhibit NHI-10 at 2.

expressly discusses the 161 MW of batteries as being available to address thermal overloads in San Diego.[17] Nevada Hydro's claim that the batteries were unavailable for dispatch and not relied upon by the CAISO not only flies in the face of the facts, it defies logic. It assumes the CAISO would ignore using resources at its disposal – resources that it previously identified in the 2018-2019 Unified Planning Assumptions and modeled in the transmission planning process – to address reliability needs.

The 2018-2019 Unified Planning Assumptions clearly stated that the CAISO does not show batteries as dispatched in its transmission planning base cases; rather, it dispatches them when there is an actual need for mitigation identified in its reliability studies. In that regard, the 2018-2019 Unified Planning Assumptions stated:

> The portion of authorized local capacity derived from energy limited preferred resources such as demand response and battery storage will be modeled offline in the initial base cases and will be used as mitigation once reliability concerns are identified.[18]

Thus, the CAISO only dispatches batteries for energy when there is an actual need for mitigation.[19] Therefore it is hardly surprising that Mr. Alaywan did not find batteries dispatched in the base cases. It is, however, telling that Nevada Hydro and Mr. Alaywan not only overlook the explanation in the 2018-2019

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[17] *Id.* at 181, 184, 189.

[18] 2018-2019 Unified Planning Assumptions at 26.

[19] Exhibit CAISO-5 at 5.

Unified Planning Assumptions, but they continue to ignore the CAISO's explanation as to how it treats batteries in its reliability planning.

Thus, the fact the CAISO's power flow base cases show only 40 MW of pumped storage resources being dispatched does not support Nevada Hydro's conclusory allegation there was no additional battery capacity available to the CAISO.[20] The CAISO dispatched the batteries and other resources as described in Mr. Millar's Sur-Rebuttal Testimony.[21]

Mr. Alaywan also argues for the first time that there is no way to predict a contingency, and therefore battery storage may not be available to meet any contingency.[22] Although the actual time when contingencies occur cannot be predicted, the CAISO can and does forecast load levels and the potential for overloads if the worst contingencies occur at the worst possible time, and it can plan accordingly.[23] This is a basic function of transmission planning. In relying on batteries and other use-limited resources such as demand response, the CAISO must forecast the amount of time the system would be at risk of potential overloads based on daily load shape information and ensure that the use-limited resources have sufficient capacity and energy to reduce loading so if the first

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[20] *Id.* at 5.

[21] *Id.* at 7-12.

[22] Exhibit NHI-13 at 4.

[23] Exhibit CAISO-5 at 18-19.

contingency occurs immediately before a high load period, the risk of overload can be mitigated if the second contingency occurs.[24]

Mr. Alaywan's unsupported contention that the CAISO cannot include batteries in its contingency planning rings hollow. Even if Nevada Hydro were correct, the same criticism would apply to pumped storage. Although pumped storage may have a longer discharge period than battery storage, there could be periods when it would be unavailable to respond to the contingency. So applying Mr. Alaywan's logic, the CAISO could not approve LEAPS to address potential contingencies in the San Diego area. Mr. Alaywan also ignores (1) the Commission's prior findings that battery storage can mitigate thermal overloads and qualify as a reliability transmission solution if selected by the independent system operator or regional transmission organization in its regional planning process to meet an identified transmission need,[25] and (2) the CAISO's prior approval of batteries as reliability transmission solutions in its transmission planning process.[26]

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[24] *Id.* Appendix G: 2028 Local Capacity Technical Study of the 2018-2019 CAISO Transmission Plan ("Appendix G") provides detailed information on load shapes supporting the consideration of energy requirements that supports the analysis necessary to ensure use-limited resources would meet reliability needs. CAISO Exhibit-5 at 18-19, referencing Appendix G, available at http://www.caiso.com/Documents/AppendixG-BoardApproved2018-2019TransmissionPlan.pdf.

[25] *Alternative Transmission, Inc.,* 168 FERC ¶61,106 at P 41 (2019); *Western Grid* at PP 45, 47.

[26] In 2018, the CAISO informed the Commission that since 2009 it had considered nearly 30 storage projects as potential transmission solutions in its transmission planning process and had approved two battery storage projects in the 2017-2018 transmission planning process to address thermal overloads. CAISO Motion to Intervene and Protest at 12, Docket No, EL18-131 (April 13, 2018).

2. Nevada Hydro Makes Other Erroneous Claims Regarding the CAISO's Reliability Assessment

Besides claiming that the CAISO's batteries were "fictitious," Nevada Hydro asserts that the CAISO failed to demonstrate there exists sufficient generation to curtail to address thermal overloads.[27] Nevada Hydro states that Mr. Alaywan's analysis, which purportedly shows residual capacity deficiencies in two scenarios the CAISO studied, relied on a CAISO generation list to identify 915 MW that the CAISO would have to curtail to relieve overloads in the San Diego Main area and alleges that the CAISO does not dispute that number.[28] Nevada Hydro also claims that the CAISO did not identify other generation it could curtail.[29]

Nevada Hydro blatantly mischaracterizes the CAISO's position. In its Reply, the CAISO vehemently disagreed with Nevada Hydro's unsupported claim that there is a residual reliability need and never agreed, either implicitly or explicitly, that there is only 915 MW of generation that can be curtailed to address overloads.[30] The CAISO stated that "Mr. Alaywan's analysis did not fully optimize the redispatch of resources" and "[h]e failed to correspondingly reduce the output of the specific generation contributing to the overload."[31]

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[27] September 5 Reply at 3-7. Nevada Hydro states that Mr. Alaywan's analysis shows a 50 MW deficiency in 2023 and a 484 MW deficiency in 2027. September 5 Reply at 3.

[28] *Id.* at 5.

[29] *Id.*

[30] CAISO August 21 Reply at 10-23.

[31] *Id.* at 13, *see also* Exhibit CAISO-4 at 4.

In his Sur-Rebuttal Testimony, Mr. Millar walks through the CAISO's process to address P6/N-1-1 contingencies in the San Diego Main area and explains the generation adjustments the CAISO made to address such contingencies, and identifies the corresponding amount of generation available to adjust at each stage.[32] Among other things, Mr. Millar identifies an additional 998 MW and 1022 MW that can be curtailed in the 2023 Summer Peak and 2028 Summer Peak cases, respectively.[33] This generation, which Mr. Millar specifically identifies, is located in the Arizona Public Service Company ("APS") service territory east of Imperial Valley and is separate and distinct from the 915 MW identified by Mr. Alaywan.[34] This generation would flow on Path 46 into southeastern California, and then, like the 915 MW of generation, it would flow into San Diego.[35] Mr. Alaywan apparently did not dispatch generation down in Arizona to reduce imports over Path 46 into California after the first contingency and to prepare the system for the possibility of the second contingency.[36] Besides the demand response and battery storage in the San Diego area, Mr.

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32 Exhibit CAISO-5 at 7-14.

33 *Id.* at 12.

34 *Id.* at 11.

35 *Id.*at 7, 11. The 915 MW of thermal generation is reflected in a contingency file the CAISO provided in the transmission planning process. It reflects generation in the Imperial Valley that is connected to a remedial action scheme that would operate and trip the generation in the event of a second contingency. Exhibit CAISO-5 at 11. The generation in the APS service territory is not shown in the contingency file that contains the 915 MW of generation to which Mr. Alaywan refers because the contingency file only identifies generation that is tripped automatically under the remedial action scheme. It does not include generation, like the generation in the APS service territory that is dispatched manually.

36 *Id.* at 7. The CAISO also notes the CAISO document on which Mr. Alaywan relies shows there is a total of 2,878 MW of generation that can automatically be curtailed under the remedial action scheme (including 1963 MW of wind and solar that can be curtailed, particularly in off peak cases) in addition to the 915 MW of thermal generation. Exhibit CAISO-5 at 16, n.7.

Millar describes the quantities of fast response demand response and batteries in the Southern California Edison ("SCE") service territory that would be dispatched up after the first contingency.[37] Thus, Nevada Hydro's claim that there were no additional resources to dispatch is incorrect.

Although Nevada Hydro provides no substantial evidence that the CAISO's reliability analysis was in any way flawed, the CAISO provides in Attachments A-C to Mr. Millar's Sur-Rebuttal Testimony power flow plots and tables showing the power flow results in support of the CAISO's reliability results.[38] These power flow plots and tables show: (1) the "unmitigated" case without adjustments that shows the need for mitigation (Millar Sur-Rebuttal Attachment A power flow plots); (2) the case with the contingency simulation steps described by Mr. Millar, including the resource adjustment mitigations, which show there are no residual reliability issues, consistent with the results in the 2018-2019 CAISO Transmission Plan and the CAISO's prior pleadings herein (Millar Sur-Rebuttal Attachment B power flow plots); and (3) the base cases modified to reflect the late retirement of 93.8 MW which show that the identified mitigations remain effective and there are no residual reliability needs (Millar Sur-

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37 *Id.* at 7-8, 10-11.

38 Nevada Hydro notes that Table 2.9-1 of the 2018-2019 CAISO Transmission Plan shows thermal capacity being dispatched in excess of the installed capacity in some studies. September 5 Reply at 6. The CAISO conducted its reliability studies based on 3,619 MW of installed thermal generation, which is greater than the amount dispatched, as shown in Table 2.9-1. *See* 2018-2019 CAISO Transmission Planning Process Stakeholder Meeting, September 20-21, San Diego Main by Frank Chen, Slide 5, available at http://www.caiso.com/Documents/Day1-Presentations-2018-2019TPPMeeting-Sep20-21-2018.pdf.

Late in the planning process, however, 93.8 MW of thermal capacity retired unexpectedly. Exhibit CAISO-5 at 6. The CAISO reflected these late retirements in a reduced installed thermal generation capacity amount in Table 2.9-1. Exhibit CAISO-5, Millar Sur-Rebuttal Attachment C shows there are no residual thermal overloads with this small reduction in thermal capacity.

Rebuttal Attachment C power flow plots). The CAISO also is providing tables tabulating the results of the power flow analysis described in Mr. Millar's Sur-Rebuttal Testimony. Millar Sur-Rebuttal Attachment D – Table 1 shows the results with and without the mitigations for the 2013 and 2029 Summer Peak cases, and Millar Sur-Rebuttal Attachment D – Table 2 shows the results after removing the 98.3 MW of late-retired generation and demonstrates that the mitigations continue to be effective and sufficient after accounting for the retirements.

The Millar Sur-Rebuttal Attachments show, contrary to Nevada Hydro's and Mr. Alaywan's claims, there are no thermal overloads or reliability problems after the CAISO applies the available mitigation measures and, therefore, there is no need for any new transmission solutions, including LEAPS, in the San Diego Main area to address reliability issues.

3. There are no Issues of Material Fact Regarding the CAISO's Reliability Assessment that Require an Evidentiary Hearing

Nevada Hydro restates that there is a 50 MW deficiency in 2013 and a 484 MW deficiency in 2027 in the San Diego area.[39] Nevada Hydro also claims that the issues regarding the batteries and generation available to the CAISO to address potential reliability contingencies in the San Diego Main area present factual questions that require a trail type hearing to resolve.[40]

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39 September 5 Reply at 3

40 *Id.* at 7.

As indicated in the CAISO's previous answers and above, Nevada Hydro has failed to advance anything approaching a credible claim that the CAISO did not correctly perform its reliability studies, comply with NERC reliability standards, and satisfy its NERC Planning Coordinator obligations. There is no basis for the Commission to establish a trial-type hearing to address these or any other claims raised by Nevada Hydro.

Even if the CAISO would be short by 50 MW in 2023 and 484 MW in 2027, this would not support Nevada Hydro's claim that LEAPS is need for reliability. By Nevada Hydro's own admission, LEAPS cannot fully meet the potential contingencies the CAISO initially identified in the San Diego Main area. First, LEAPS would not even be in service until 2025 at the earliest.[41] One case Nevada Hydro takes issue with involves 2023, and thus, if the CAISO needed a new transmission solution to address contingencies that might occur in 2023, the CAISO would have to approve a new reliability solution that would be in service by then. This would further reduce the need for LEAPS in subsequent years. Second, Nevada Hydro admitted that even after LEAPS went into service "LEAPS would not fully solve the overloads" in 2028.[42]

Finally, regarding Nevada Hydro's claim these are issues of material fact requiring a hearing before a Commission Administrative Law Judge, if there is any concern the CAISO is shirking its responsibility as a NERC-registered Planning Coordinator and not addressing identified reliability needs, that is a

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[41] Exhibit NHI-7.

[42] Exhibit NHI-10 at 10.

matter for NERC to decide in the first instance, not an Administrative Law Judge in a litigated proceeding to determine whether the CAISO should have approved LEAPS as a transmission solution in its planning process. The CAISO must annually certify to NERC it has complied with the TPL Reliability Standards and addressed all identified reliability needs, and the findings in its 2018-2019 CAISO Transmission Plan are the basis for such certification. Nevada Hydro basically claims that the CAISO is falsely certifying to NERC, which can have significant consequences. NERC can audit the CAISO's conclusions and act appropriately if it believes there is the potential the CAISO failed to adequately fulfill its Planning Coordinator obligations. If the Commission has questions regarding the CAISO's performance of its reliability planning functions, it can convene a conference; there is no need or basis for a trial-type hearing. Nevada Hydro has provided no documentation to support its conclusory assertions. But the CAISO has (1) shown that the 161 MW of batteries are not "fictitious" (2) identified the specific additional generation (beyond the 915 MW identified by Mr. Alaywan) the CAISO can curtail, and (3) demonstrated that its solutions meet the identified reliability needs.

B. Nevada Hydro's Allegations Regarding the CAISO's Economic Planning Process Findings Are Misplaced and Misrepresent the CAISO's Studies and Statements

1. LEAPS' Negative $132 Million Net Load Payment does not "Come Entirely from a Curtailment Estimate" and the CAISO did not "Separately Estimate the Congestion Effect of LEAPS"

Nevada Hydro, relying on Mr. Alaywan's Sur-Rebuttal Testimony, erroneously claims that the CAISO's Reply "confirms" that the negative $132 net load payment for LEAPS “comes entirely from a curtailment estimate” and that the “CAISO separately estimated the congestion effect of LEAPS.”[43] Mr. Alaywan refers to the negative 132 million value as “a cost to load of $132 million as a result of LEAPS’ relieving curtailments,” and “CAISO’s negative $132 million estimate is attributable to current curtailment conditions…”[44]

Nevada Hydro misrepresents the CAISO’s transmission planning study results and misrepresents the CAISO’s prior statements on this issue. Contrary to Nevada Hydro’s claims, the CAISO did not separately study congestion and curtailments, and the negative $132 amount does not come entirely from a “curtailment estimate.” As the CAISO already explained, consistent with the Transmission Economic Assessment Methodology (“TEAM”)[45] and as described

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43 September 5 Reply at 9. Nevada Hydro claims that the CAISO’s August 21. 2019 reply “confirms this by arguing that it did not substitute curtailment payments for congestion.” September 5 Reply at 9, referring to page 33 of the CAISO August 21 Reply. Nevada Hydro completely misrepresents the CAISO’s discussion at page 33 of the CAISO August 21 Reply. Nowhere does the CAISO state that the negative $132 million figure comes from a curtailment estimate or that the CAISO separately estimated the congestion benefits of LEAPS. In particular, nowhere on page 33 of the CAISO August 21 Reply does the CAISO “argue that it did not substitute curtailment payments for congestion” as claimed by Nevada Hydro. At page 33, the CAISO merely responded to Nevada Hydro’s prior claim that the CAISO did not study the congestion benefits of LEAPS. *See* September 5 Reply at 17-18; Exhibit NHI-10 at 14. The CAISO pointed out that its production cost modeling did in fact assess, among other benefits, the congestion benefits of LEAPS. The CAISO also noted that, in addition to its baseline production cost modeling study of LEAPS, the CAISO also conducted a sensitivity production cost modeling study of LEAPS, locating LEAPS at a relatively unconstrained point on the system. This study confirmed that LEAPS was not providing significant congestion cost benefits, and that most of its benefits arose through market participation. Nevada Hydro misrepresents these production cost modeling studies as only having studied congestion. That is incorrect. They were full production cost modeling studies. The CAISO was merely discussing the congestion-related results of its studies to respond to Nevada Hydro’s specific claim that the CAISO failed to assess the congestion benefits of LEAPS. The CAISO did not state that that the net load payment from LEAPS came entirely from a curtailment estimate or that it separately estimated the congestion and curtailment effects of LEAPS.

44 Exhibit NHI-13 at 6-7.

45 TEAM is attached to the CAISO’s Answer to Complaint as Exhibit CAISO-2.

in the 2018-2019 CAISO Transmission Plan, the CAISO conducted a production cost modeling study with and without LEAPS that considered all benefits to CAISO ratepayers.[46] The CAISO did not conduct a separate production cost modelling effort to assess congestion and then another for curtailments (or any other component of TEAM). The CAISO's production cost model reflected all of the costs and revenues arising from LEAPS to determine CAISO ratepayer benefits.

Nevada Hydro's claim that the negative $132 million net load payment "comes from curtailment"[47] is untrue, overly simplistic, and fails to account for the full scope of the CAISO's production cost simulation, including the numerous elements that comprise the net load payment and the myriad factors affecting it.[48] Nevada Hydro inappropriately attributes the entire load payment value to one factor when there are many influences on the level of the net load payment.[49] In his Sur-Rebuttal Testimony and prior submissions,[50] Mr. Millar describes the production cost simulation process and the factors that contribute to the net result.[51] The negative $132 million simply reflects the cumulative effect of LEAPS on the net load payment in the CAISO markets because of the production cost simulation. This includes the overall effect of LEAPS on

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[46] CAISO August 21 Reply at 30 ("The CAISO economic planning studies accounted for all benefits to CAISO ratepayers associated with a proposed economic project, including any congestion and curtailment-related benefits."), *see also* Exhibit CAISO-5 at 20.

[47] Exhibit NHI-13 at 7.

[48] Exhibit CAISO-5 at 19-22.

[49] *Id.* at 19.

[50] *Id.* at 19-22; Exhibit CAISO-2 at 34, and Exhibit CAISO-4 at 7.

[51] Exhibit CAISO-5 at 19-22.

congestion cost, locational marginal prices ("LMPs") while charging, and LMPs while discharging. The production cost simulation is not, as Nevada Hydro continues to claim, merely an "estimate of curtailment." These impacts are driven by numerous factors, including the change of power flows with adding LEAPS, the location of transmission constraints, the specific units whose LMPS are affected and whether such units return their benefits to CAISO ratepayers, the levels of congestion at the time of charging and discharging, and the steepness of the price curve (both upward and downward), and the magnitude of step changes (upward and downward) in pricing. Nevada Hydro also ignores the significant market revenues earned by LEAPS returned to CAISO ratepayers and are not included in the net load payment amount. Although Mr. Millar discusses these matters further in his Sur-Rebuttal Testimony in an attempt to rectify the confusion sown by Nevada Hydro, the fundamental flaw in Nevada Hydro's arguments regarding the results of the CAISO's economic analysis is its attempt to reduce a complicated and multi-faceted analysis into overly-simplistic, contrived descriptions that misrepresent the CAISO's statements and analysis.

2. Nevada Hydro's Unsupported Claim that the CAISO's Methodology Prevents Storage Resources from Being Economic Is Misplaced

Nevada Hydro continues to tout the ability of LEAPS to absorb energy during periods of overgeneration and reduce renewable resource curtailments.[52] Mr. Alaywan asserts that the CAISO "inappropriately treated the transmission

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[52] September 5 Reply at 12; Exhibit NHI-13 at 9.

benefit of LEAPS as a detriment".[53] He claims that "if energy storage to relieve the over-generation problem increases the cost to load by making prices less negative, it would never be economic."[54] Further, he claims that if the CAISO's cost curve calculation method is correct, storage can never qualify as a transmission asset through the economic study request process.[55]

These unsupported, conclusory, and false claims further reflect Nevada Hydro's predetermination that its $2 billion project must be cost-effective regardless of what the CAISO's studies show. Nevada Hydro identifies no specific flaws in the CAISO's production cost simulation and did not conduct its own production cost simulation. Instead, Nevada Hydro relies on trite assumptions about the general curtailment benefits of pumped storage, as well as hyperbole and inflated rhetoric regarding the purportedly broad implications of the CAISO's study of LEAPS.

The CAISO's production cost analysis results provide estimates of all benefits resulting from LEAPS considering impacts on load payments into the market and also generation and transmission revenue benefits accruing back to CAISO ratepayers. However, the production cost analysis must also consider the offsetting impact the charging the pumped storage unit has on increasing prices paid by load in the market, which may not entirely flow to generators

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[53] Exhibit NHI-13 at 7.

[54] *Id.*

[55] *Id.*

whose benefits accrue to ratepayers.[56] Nevada Hydro ignores that increased load (from pumping, *i.e.,* charging) will increase LMPs.[57]

Nevada Hydro also focuses solely on one component of the CAISO's production cost simulation and ignores that the overall production cost simulation showed positive – not negative – benefits for LEAPS after considering all benefits accruing to CAISO ratepayers – including LEAPS' market revenues.[58] But the benefits did not offset the capital costs of the project. Nevada Hydro ignores (1) the fact that a project would have to demonstrate significant economic benefits to justify a $2 billion project cost and (2) the added difficulty in achieving such benefits when such project provides limited congestion relief benefits.

Nevada Hydro further ignores that eight proposed economic projects in the San Diego area that the CAISO studied in the 2018-2019 transmission planning process, including projects with costs significantly lower than LEAPS, failed to show a benefit-to-cost ratio even close to 1:1.[59] This indicates that congestion and other economic needs in the San Diego Main area simply are not substantial enough in the planning horizon studied to justify a major economic transmission project in the area, let alone a $2 billion project. For example, as

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56 Exhibit CAISO-5 at 22.

57 *Id.*

58 2018-2019 CAISO Transmission Plan at 359. Just because a storage facility provides economic benefits does not mean it is providing a needed transmission service. Although LEAPS includes a transmission line which provides a transmission function, the LEAPS pumped storage facility is functioning as a generator and load in the market, and that is where its benefits derive.

59 The CAISO notes that it approved the S Line Series Reactor Project, which had a capital cost of only $30 million and had a benefit-to-cost ratio ranging from 1.54 to 2.36. 2018-2019 CAISO Transmission Plan at 321-24.

shown in the 2018-2019 CAISO Transmission Plan, congestion in the San Diego area that new projects might relieve is limited.[60] The CAISO's planning studies also showed that the economic benefits of LEAPS were comparable to a pumped storage facility in an uncongested location in southern California.[61]

Mr. Alaywan points to the results from the 2018-2019 CAISO Transmission Plan for the North Gila-Imperial Valley #2 500 kV transmission line ("North Gila") and the proposed HVDC Conversion Project ("HVDC Conversion") and falsely claims that because the results differed from LEAPS the CAISO must not have used the same methodology to calculate curtailment costs and benefits for those projects that it used for LEAPS.[62] In the 2018-2018 CAISO Transmission Plan the CAISO discusses the production cost modeling analysis it applied to all economic projects it studied.[63]

Mr. Alaywan's suggestion that the different cost results for these projects, compared to LEAPS, must result from a discrepancy in the CAISO's studies is spurious. Mr. Alaywan provides no evidence that the CAISO used different methodologies to assess different projects, nor is there any. Instead, he resorts to bald assertions. Mr. Alaywan ignores the fact that the two projects he identifies are transmission line-only projects, not pumped storage units (with connecting transmission line(s)) like LEAPS. The results for the North Gila and

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60 *See* 2018-2019 CAISO Transmission Plan, Table 4.7-2 at 243 (showing aggregated potential congestion on the CAISO Controlled Grid in 2028) and Table 4.7-3 at 245 (showing $2.97 million in San Diego congestion).

61 *Id.* at 354.

62 *Id.*

63 *Id.* at 226-38.

the HVDC Conversion differ from LEAPS for one obvious reason – LEAPS must first be charged to supply energy later, and the charging drives up LMPs at the time the charging is taking place. Neither transmission line project involved considering the impact of charging on LMPs (and the resulting cost impacts on CAISO ratepayers).[64]

The two transmission line projects caused increased load payments, and had varying impacts on offsetting generator revenues and transmission revenues. These results simply demonstrate that depending on location, a new transmission line can cause increasing system-wide load payments by redistributing flows over paths into a load pocket that actually drive up congestion along with the need for additional generation to be dispatched on the load side of the constraint.[65] This can occur when the proposed transmission line reduces impedances on a particular path into a load pocket with thermal limitations downstream of the new transmission line, pulling flows from other paths into the same pocket coming in from different directions. As Mr. Millar indicates, the CAISO has observed this multiple times regarding proposed new transmission lines.[66]

Regarding the proposed North Gila-Imperial Valley #2 500 kV transmission line, beside concerns expressed in the 2018-2019 CAISO Transmission Plan regarding increasing flows on a path with downstream

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64 Exhibit CAISO-5 at 27-28.

65 *Id.*

66 *Id.* at 28.

constraints,[67] the CAISO noted in the 2018-2019 CAISO Transmission Plan that since the 2014-2015 CAISO Transmission Plan, there has been a need to bypass series capacitors on the existing 500 kV lines already in this corridor (Sunrise and Southwest Power Link) to increase impedances and push power away from other upstream or downstream facilities to mitigate overloads.[68] Similarly, the CAISO observed that the HVDC Conversion Project increased congestion along the Suncrest to Sycamore corridor and on Path 26.[69] Although these circumstances did not have the same impact on load payments compared to the market impact of charging a pumped storage facility such as LEAPS, they nonetheless resulted in increases in load payments into the market.

Nevada Hydro's attempt to draw a direct correlation between the amount of total curtailment and the load payment component of the overall CAISO ratepayer benefit impact is overly simplistic and does not take into account the actual details of projected energy price curves, impacts of charging pumped storage for later generation, and the boundaries of load and generation pockets (which change at various load levels), as well as the distribution of merchant generation, utility owned generation, and generation that has a power purchase agreement ("PPA") with load serving entities.

Nevada Hydro also conveniently ignores that the CAISO's production cost modeling showed significantly higher production simulation CAISO ratepayer

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[67] 2018-2019 CAISO Transmission Plan, Section 4.9.11.3 at 332.

[68] 2018-2019 CAISO Transmission Plan, Section 2.9.5 at 188.

[69] 2018-2019 CAISO Transmission Plan, Section 4.9.11.2 at 326.

benefits for LEAPS compared to these two transmission line projects – $34 million annually for LEAPS compared to $6 million annually (for North Gila) and negative $13 million annually (for the HVDC Conversion).[70]

3. Nevada Hydro's Arguments Regarding the Impact of Power Purchase Agreements are Misplaced and Misrepresent CAISO Statements

Nevada Hydro asserts that the CAISO fails to support the claim that reductions in curtailments to load create a negative benefit to load.[71] Nevada Hydro notes that the payments by generators during negative pricing gets paid back to generators under PPA reconciliation because the PPAs are typically contracts for differences.[72] Mr. Alaywan states that the CAISO fails to account for this and that, when this price reconciliation is factored in, decreasing curtailments benefit load and are not the "detriment that CAISO is attempting to portray."[73] He adds that "[t]here simply is no way to rationalize Mr. Millar [sic] assertion that curtailing already paid-for renewables is beneficial to loads."[74]

As an initial matter, Nevada Hydro and Mr. Alaywan misrepresent the CAISO's and Mr. Millar's statements. The CAISO has never stated that curtailing renewables benefits loads or that a project reducing curtailments does not benefit load. Nevada Hydro quotes no CAISO statement to the contrary. Indeed, the

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70 LEAPS also has significantly higher costs ($2 billion) than the two transmission line projects – $291 million for North Gila and $900 million for the HVDC Conversion.

71 September 5 Reply at 9.

72 *Id.*

73 Exhibit NHI-13 at 14.

74 *Id.*

CAISO's production cost simulation study results show positive monetary benefits for LEAPS and all the other storage projects the CAISO studied in the 2018-2019 transmission planning process. Those benefits simply were insufficient to offset project costs. That outcome does not warrant ignoring one of the factors that led to a lower overall benefit – the effect on LMPs of pumping – as Nevada Hydro recommends, just to get the result it seeks.

Regardless, Nevada Hydro's arguments regarding the impact of PPAs are misplaced. The CAISO's production cost methodology considers the incremental changes to LMPs (and revenues) and the specific units whose revenues are increasing (or decreasing) – whether they are merchant units or PPA units/utility retained generation – that would result from adding a new project, compared to the production cost simulation without the new project.

As Mr. Millar discusses, PPAs and utility ownership of generators plays an important role in determining which benefits of increased LMPs flow back to CAISO ratepayers.[75] Increasing LMPs initially trigger higher payments into the market and increased revenues for generators. Under the transmission economic analysis methodology, PPA's based on contracts for differences cause the return of excess market revenues to load if prices are high, and shortfalls are recovered from load if LMPs are low. However, for purposes of studying the incremental impact of a transmission addition, the actual level of the strike price in an individual PPA is irrelevant because it remains constant both before and after the addition of the proposed transmission facility in the production cost

[75] Exhibit CAISO-5 at 23-26.

simulation. When a generator is returning excess revenues to load, the incremental effect being measured is the incremental change to the refund because of the new project, not the absolute magnitude of the refund. The CAISO is studying the incremental benefits of the potential transmission addition, not deciding if the PPA itself was a good deal.

Regarding curtailment risk, the CAISO's analysis assumes the risk of curtailment to generators with PPAs is borne by load customers. For generators under a PPA, fixed price PPAs reflecting take or pay provisions that pass curtailment risk to the load customers are essentially a sunk cost to the load and do not change regardless of adding a new transmission facility. Load pays the price for a specified quantity of energy whether or not production from the generator is curtailed.[76] The market impact on revenues based on production volumes and price differences do get reflected in the differences between before- and after-production simulation studies. However, not all generators are under a PPA. It is therefore necessary to consider all of the impacts of a proposed project, including what other generation is affected by the curtailment and if the constraints are local creating "generation pockets" or if the negative prices are being experienced across the entire CAISO footprint. Further, the benefit of pumped storage to load arises from using low cost energy to pump – which may

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[76] *Id.* at 25. In that regard, if load has agreed to pay a supplier a strike price of $30 for 50 MW, load pays the total amount of $1,500 regardless of whether some portion of that load is curtailed. If the supplier pays $10 per MWh because the prices is negative $10 in the CAISO's market to produce the 50 MW, load will pay the supplier $2,000, but the load will also receive $500 through the CAISO market, reflecting the negative price the supplier paid in the market. The end result is load making a net payment of $1,500. That payout level is "sunk" whether load pays it through the market or through a PPA reconciliation.

reduce curtailment – and selling that energy to the market during high cost periods.[77]

In conclusion, the CAISO has never said that reducing curtailments provides no benefit. The CAISO has said that that one needs to consider the factors that affect and determine the total benefits of a project. Nevada Hydro fails to account for many considerations. First,, Nevada Hydro ignores that LMPs increase when a pumped storage unit is charging (*i.e.*, absorbing energy that might otherwise be curtailed), which as the most basic level reflects the simple laws of supply and demand. Second, Nevada Hydro ignores that not all generators have a PPA, and when LMPs increase, more monies are paid to resources that do not return the dollars to load, thus increasing the costs to CAISO ratepayers. Third, load pays the "strike price" in a negotiated PPA regardless of whether energy is curtailed and what the market price is and regardless of whether LEAPS exists. Fourth, the financial benefits a pumped storage unit ultimately accrue when the unit is discharging and selling energy. When it is dispensing and selling the energy into the market, the pumped storage unit is lowering LMPs **and** earning energy market revenues, which must be taken into account in determining the total benefits of the facility. In other words, the economic value of LEAPS results in large part from the cumulative effect of pumping at a low price and then selling the energy later on at a higher price. Nevada Hydro accepts the benefits of generating and selling the stored electricity but fails to recognize the increased LMPs resulting from the pumping function,

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77 *Id*.

which is a necessary precursor to its energy sales. Nevada Hydro also selectively focuses on one element of the CAISO's production cost simulation – the negative net load payment number – to claim that the CAISO fails to recognize the value of LEAPS. Nevada Hydro fails to acknowledge other elements of the equation, in particular the fact that LEAPS earns significant market revenues from discharging, which the CAISO credited to LEAPS. Importantly, Nevada Hydro continues to ignore that LEAPS' production cost simulation benefits do not offset its significant costs.

4. Nevada Hydro Is Not Entitled to any Benefit Under Section 2.5.5 of TEAM

Mr. Alaywan also claims that under Section 2.5.5 of TEAM, the CAISO should have credited LEAPS with a $42.7 million annual credit for avoiding curtailments.[78] This is based on 927 GWh of annual energy curtailment multiplied by $46.06 (based on average CAISO energy market prices).[79] The CAISO has previously explained why LEAPS is not entitled to the benefit under Section 2.5.5 of TEAM.[80] Nevada Hydro is attempting to dictate or second guess the CPUC's procurement decisions (which included a decision not to procure pumped storage), and have the LEAPS pumped storage unit function as a replacement supply resource in lieu of other resources the CPUC prefers. This does not make LEAPS a transmission asset. TEAM Section 2.5.5 is entitled

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78 Exhibit NHI-5 at 9.

79 *Id.*

80 CAISO Answer to Complaint at 91-102; CAISO August 21 Reply at 41-44.

Public Policy Benefit, and consistent with Commission orders, the CAISO tariff, TEAM, and the 2018-2019 Unified Planning Assumptions the CAISO looks to the CPUC and local regulatory authorities to provide renewable resource portfolios and public policy requirements.[81]

Moreover, Nevada Hydro's calculation of "benefits" is inconsistent with TEAM Section 2.5.5, which contemplates a cost savings based on "avoiding over-build." Nevada Hydro's calculation is based on average pool prices for energy costs, not the "cost saving from avoiding overbuild." TEAM Section 2.5.5 does not contemplate a benefit based on calculating the energy costs of curtailed generation. Nevada Hydro's calculation is inappropriate. The CAISO's production cost simulation assessed the economic impacts of LEAPS, considering the impacts of pumping and discharging on the market, and tracking which generation and transmission benefits accrue to CAISO ratepayers.[82] Nevada Hydro's overly simplistic calculation of the price to avoid curtailments ignores all of the considerations that go into the TEAM production cost simulation calculation. In particular, it ignores the costs associated with LEAPS pumping activities.

Mr. Alaywan also states that the 927 GWh translates to approximately 353 MW of installed capacity that would cost about $388 million and could be

[81] *Cal. Indep. Sys. Operator Corp.,* 133 FERC ¶61,224 at P 162 (2010); CAISO Tariff Sections, 24.3.1; 24.4.6; Business Practice Manual for the Transmission Planning Process at 22, 24, 49. TEAM Document, Exhibit CAISO-2 at 21; 2018-2019 Unified Planning Assumptions at 19-20.

[82] Exhibit CAISO-5 at 29.

avoided.[83] He states this avoided capital cost is close to the $73 million in avoided renewable portfolio standard ("RPS") capital costs the CAISO identified in its 2018 storage sensitivity studies.[84] Mr. Alaywan then argues that the CAISO should have counted both the $42.7 million and the avoided capital cost of $73 million.[85] He suggests that the avoided curtailment cost will allow for more efficient use of existing generation that load has agreed to pay for through PPAs.[86]

Finally, even if Nevada Hydro was entitled to a TEAM Section 2.5.5 benefit, Nevada Hydro cannot have it both ways. Nevada Hydro is inappropriately "double dipping" by seeking a benefit both for the purported avoided capital costs of renewable resources, while at the same time arguing that it should be credited with what it claims is a benefit associated with curtailing the energy of the resources it asserts would not even need to be built.[87] Even if the Commission were to accept Nevada Hydro's invitation to require the CAISO to supplant the CPUC's generation procurement decisions by determining that

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83 Exhibit NHI-13 at 10.

84 *Id.* As discussed in prior pleadings herein, the CAISO's studies were intended to inform the CPUC's generation procurement and planning proceeding and discuss storage as one of several generation supply options for a diverse generation fleet. Also as discussed previously, the CPUC expressly declined to include pumped storage in its recommended resource portfolio. Nevada Hydro also ignores that the resource portfolio that was considered in the 2018 storage sensitivity study is not the same resource portfolio the CAISO used in the 2018-2019 transmission planning process.

85 *Id.*

86 *Id.*

87 Later in his sur-rebuttal testimony, Mr. Alaywan suggests the avoided curtailment benefit should still be counted in addition to any avoided cost of new generating plants because it "allow[s] for more efficient use of existing generation that load has already committed to pay through power purchased agreements." Exhibit NHI-13 at 10. The CAISO's production cost modeling already captured the benefits of LEAPS in this regard (for all existing and assumed generation), so, adding Mr. Alaywan's proposed benefit would be duplicative.

LEAPS should replace renewable generation identified in the CPUC's portfolios, the CAISO would have to redo its production cost simulation studies to reflect a lower amount of renewable generation than was included in its studies. This in turn would reduce the production cost simulation benefits attributed to LEAPS because there would be less generation to curtail. In any event, Nevada Hydro is ineligible for a TEAM section 2.5.5 benefit, and there is no authority for the CAISO to dictate or supplant CPUC generation procurement functions.

C. The CAISO Properly Considered the CPUC's Default Portfolio

Nevada Hydro argues that the CAISO adopted the CPUC's generation planning assumptions "without critical evaluation" and failed to use its "independent judgment regarding transmission planning inputs."[88] Nevada Hydro further alleges that the CAISO's 2018-2019 Unified Planning Assumptions restrict the CAISO's ability to model generating resources in the CPUC's default scenario unless those resources are under contract or under construction.[89] This view reflects a misreading of the 2018-2019 Unified Planning Assumptions and is contrary to actual practice.

Section 3.7.2 of the CAISO's 2018-2019 Unified Planning Assumptions, which is specifically focused on renewable generation assumptions, states:

> The CPUC issued a decision on February 08, 2018 which adopted the integrated resource planning (IRP) process designed to ensure that the electric sector is on track to help the State achieve its 2030 greenhouse gas (GHG) reduction target, at least cost, while maintaining electric service reliability and meeting other State goals.

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88 September 5 Reply at 14.

89 *Id.* at 15.

> Based on the proposal voted on and adopted by the CPUC, **a "Default Scenario" will be transmitted to the California ISO to be used in the 2018-2019 TPP reliability assessment**. The Unified Inputs and Assumptions document19 describes the Default Scenario which corresponds to 50% RPS. Renewable resources under development with CPUC-approved contracts with the three investor-owned utilities were assumed to be part of the baseline assumptions while creating the Default Scenario portfolio. The ISO will work with the CPUC to identify such resources and model[20] these in the reliability assessment base cases. The ISO may supplement this scenario with information regarding contracted RPS resources that are under construction as of May 2018. (emphasis added and footnotes omitted).[90]

The bolded portion clearly states that the CPUC's Default Scenario would be used in the 2018-19 transmission planning process reliability assessment. Nevada Hydro argues that the subsequent sentences show the CAISO's error in accepting generating resources in the Default Scenario that had "no contracts or construction activity."[91] Nevada Hydro misreads the text. After noting that the Default Scenario will be used for the reliability assessment, the subsequent sentences in this paragraph simply note how the Default Scenario is built and supplemented.

The second sentence in the paragraph notes that the CPUC included renewable resources with CPUC-approved contracts in the baseline assumptions when creating the Default Scenario. The CAISO noted this because in prior years the CPUC did not include contracted renewable resources in its baseline assumptions; rather, it included them in the general renewable portfolio

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90 2018-2019 Unified Planning Assumptions at 19-20.

91 Exhibit NHI-13 at 15.

buildout.[92] The last sentence of section 3.7.2 of the 2018-2019 Unified Planning Assumptions notes that the CAISO "may supplement this scenario [*i.e.*, the CPUC's Default Scenario] with information regarding contracted RPS resources that are under construction as of May 2018."[93] It is appropriate to supplement the CPUC's generation portfolios with resources under construction, especially because non-CPUC jurisdictional entities contract with resources not reflected in the CPUC's renewable generation portfolios. By supplementing the CPUC's generation portfolios with under construction resources, the CAISO can provide a more accurate model of planned renewable generation. However, this supplementation does not suggest that the CAISO should (or will) remove or ignore resources in the CPUC's renewable generation portfolios. The CAISO's position is confirmed by discussion in section 2.3.4.2 *–Renewable Generation* of the 2018-2019 CAISO Transmission Plan, which notes, among other things, that "[g]eneration included in this year's baseline scenario as described in Section 24.4.6.6 of the ISO Tariff was also included in the 10-year Planning Cases."[94] The baseline scenario reflected the CPUC's Default Portfolio.[95]

Besides distorting the plain language of the Unified Planning Assumptions, Nevada Hydro's effort to second-guess the CPUC's renewable generation planning is contrary to years of past practice and coordination between the

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[92] The CAISO described this change in an earlier filing in this proceeding. CAISO Answer to Complaint at 54, n. 162.

[93] 2018-2019 Unified Planning Assumptions at 20.

[94] 2018-2019 CAISO Transmission Plan at 52.

[95] *Id.* at 191-93.

CAISO and the CPUC. As the CAISO has stated in past transmission planning cycles, it uses the CPUC's renewable generation portfolios as the base case renewable resource portfolio.[96] The 2018-2019 CAISO Transmission Plan also noted that "generic dynamic data may be used for the future generation" due to data availability issues.[97] Nevada Hydro's suggestion that the CAISO should use its "independent judgment" to undo CPUC generation planning and procurement decisions would significantly undermine the coordination efforts that have allowed the CAISO to identify needed transmission projects and successfully support those projects through the CPUC's permitting and environmental review processes.

D. Nevada Hydro's Statements Further Confirm that the LEAPS Pumped Storage Unit is not Providing a Needed Transmission Service

Nevada Hydro states that LEAPS will benefit CAISO ratepayers because it will operate the pumps during low-priced hours and produce energy during later hours of the day when there is less supply and, thus, higher prices (which would flow back to ratepayers).[98] The mere fact that Nevada Hydro will flow back revenues to ratepayers does not make the LEAPS pumped storage facility a

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[96] *See, e.g.,* 2017-2018 CAISO Transmission Plan at 51(March 22, 2018) available at: http://www.caiso.com/Documents/BoardApproved-2017-2018_Transmission_Plan.pdf; 2017-2018 Unified Planning Assumptions and Study Plan at 22 (March 31, 2017) available at: http://www.caiso.com/Documents/Final2017-2018StudyPlan.pdf; 2016-2017 Unified Planning Assumptions and Study Plan at 17-18 (March 31, 2016) available at: http://www.caiso.com/Documents/Final2016-2017StudyPlan.pdf.

[97] 2018-2019 CAISO Transmission Plan at 52; *see also* 2017-2018 CAISO Transmission Plan at 51.

[98] September 5 Reply at 13.

transmission asset. If that were the case every storage unit that agrees to cost-based rates with a claw-back of market revenues would be considered a transmission asset regardless of the actual function it performs or whether the resource is the more cost effective solution to meet an identified transmission need.

The Commission has recognized that storage can be transmission, distribution, generation, or load, and the Commission will determine which it is on a case-by-case basis given the specific functions the resource is providing and the specific transmission needs the regional planning authority requires the resource to meet.[99] The CAISO has shown that the LEAPS pumped storage unit is functioning as generation and load, not transmission.[100] This is confirmed by Nevada Hydro's own statements that LEAPS benefits arise from arbitraging the energy markets, pumping when prices are low and discharging when there is less supply and higher prices. This distinguishes the LEAPS pumped storage facility from the pumped storage facility in *Western Grid* that the Commission found could be transmission because it was not arbitraging the energy markets.[101]

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99 *Western Grid* at P 44.

100 CAISO Answer to Complaint at 111-124; CAISO August 21 Reply at 52-57.

101 *Western Grid* at P 46; *see also Third-Party Provision of Ancillary Servs; Accounting and Fin. Reporting for New Electric Storage Tech.,* Notice of Inquiry, 135 FERC ¶ 1,240 at n. 47 (2011) (noting that a storage unit acts like a generator when it arbitrages differences in peak and off-peak energy prices or sells ancillary services).

IV. CONCLUSION

For the foregoing reasons and the reasons set forth herein and in the CAISO's prior filings in this proceeding, the Commission should reject Nevada Hydro's Complaint.

Respectfully submitted,

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Dated: September 20, 2019

CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing document upon the parties on the official service list for the above-referenced proceeding, under the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2010).

Dated at Folsom, California, this 2^{0th} day of September, 2019.

/s/ Grace Clark
Grace Clark

EXHIBIT CAISO-5

Sur-Rebuttal Testimony of Neil Millar

Exhibit CAISO-5

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

The Nevada Hydro Company Inc.	)	
	)	
v.	)	**Docket No. EL19-81-000**
	)	
California Independent System Operator Corp.	)	
	)	

SUR-REBUTTAL TESTIMONY OF NEIL MILLAR

Q. Please state your name.

A. Neil Millar.

Q. Are you the same Neil Millar that submitted a declaration and rebuttal testimony accompanying the CAISO's previous answers to Nevada Hydro in this proceeding?

A. Yes. My background and qualifications are set forth in my declaration.

Q. What is the purpose of your rebuttal testimony?

A. In this testimony, I respond to certain claims made by Nevada Hydro's witness Mr. Alaywan in his sur-rebuttal testimony ("Exhibit NHI-13") submitted with Nevada Hydro's September 5 reply to the CAISO ("September 5 Reply"). Specifically, I point out several flaws in Mr. Alaywan's assumptions and analysis of the reliability issues in the San Diego area that cause him to incorrectly forecast capacity shortfalls in that area during the planning horizon associated with the 2018-2019 CAISO Transmission Plan. I also respond to several criticisms that Mr. Alaywan raises regarding the CAISO's economic planning studies of LEAPS.

Reliability Issues

Q. Mr. Alaywan disagrees with the CAISO's reliance on "201 MW of batteries" in the 2018-2019 CAISO Transmission Plan, claiming on page 2 of his sur-rebuttal testimony that Appendix A to the CAISO's transmission planning report only shows 40 MW of batteries. How do you respond?

A. First, it is not surprising that Mr. Alaywan did not identify "201 MW of batteries" in Appendix A: System Data ("Appendix A") of the 2018-2019 CAISO Transmission Plan and this does not indicate any flaw in the CAISO's analysis. Appendix A identifies "Existing Generation," Retired Generation," and "Planned Generation." It does not list, nor claim to list, batteries or any other preferred resources such as demand response. The battery capacity that the CAISO considered in its reliability assessments is listed by planning area in chapter 2 of the 2018-2019 CAISO Transmission Plan, with each individual area's reliability discussion.

Second, with respect to Mr. Alaywan's assertion that 40 MW of batteries are listed in Appendix A, he is incorrect. As I already explained in my rebuttal testimony, the storage resources that the CAISO relied on in conducting its reliability analysis for the San Diego area does not consist of 201 MW of batteries, but rather, 40 MW of *hydro pumped storage*, and 161 MW of battery storage, totaling 201 MW of storage.[1] Thus, the 40 MW of energy storage that *is* listed in Appendix A represents the Lake Hodges

[1] See Millar Rebuttal Testimony (August 21, 2019) ("Exhibit CAISO-4") at 4.

Pumped Storage Unit, which is a hydroelectric facility, not a battery. Incidentally, the Lake Hodges Pumped Storage Unit operates in the electricity market and is not a transmission asset.

The battery storage projects modeled in the 2018-2019 CAISO Transmission Plan in the San Diego area consist of batteries that are either in service (77.5 MW), or procurement has been authorized by the California Public Utilities Commission ("CPUC") and there is a contract in place with a load serving entity (83.5 MW). I have itemized the batteries modeled in the San Diego area in the table below. As these resources are already in service or subject to an existing contract, I have also identified the source of the procurement.

Table 1: Battery Storage in San Diego modeled in 2023 and 2028 Base Cases (2018-2019 Transmission Planning Process)

Bus No.	Bus Name	kV	ID	MW	Procured via[1]:	In Operation	Interconnection Queue Number (Market Resource ID if in operation)	Market GEN_UNIT_NAME (if in operation)
22484	MIRAMAR1	69	S2	30	CPUC Decision (D.)13-10-040	Contracted	Q1434	
22256	ESCNDIDO	69	S2	6.5	CPUC Decision (D.)13-10-040	Contracted[2]	WDAT132	
22664	POMERADO	69	S2	3	CPUC Decision (D.)13-10-040	Contracted[2]	WDAT152 and 153	
22020	AVOCADO	69	S2	40	CPUC Decision (D.)13-10-040	Contracted	Q1169	
22112	CAPSTRNO	138	S2	4	CPUC Decision (D.)13-10-040	Contracted[2]	WDAT100, 101, and 118	
22256	ESCNDIDO	69	1	30	CPUC Resolution E-4791	Operational	ESCNDO_6_EB3BT3	Escondido BESS 3
							ESCNDO_6_EB1BT1	Escondido BESS 1
							ESCNDO_6_EB2BT2	Escondido BESS 2
22208	EL CAJON	69	1	7.5	CPUC Resolution E-4791	Operational	ELCAJN_6_EB1BT1	Eastern BESS 1

Bus No.	Bus Name	kV	ID	MW	Procured via[1]:	In Operation	Interconnection Queue Number (Market Resource ID if in operation)	Market GEN_UNIT_NAME (if in operation)
23216	ME GEN 1_BS2	0.64	1	20	CPUC Decision (D.)13-10-040	Operational	VSTAES_6_VESBT 1	Vista Energy Storage
23541	ME GEN 1_BS1	0.64	1	20	CPUC Decision (D.)13-10-040	Operational		
Total				**161**				

1. CPUC Decision (D.)13-10-040 stemmed from CPUC long-term procurement planning proceedings. CPUC Resolution E-4791 was issued to address electrical reliability risks due to the (then) moratorium on injections into the Aliso Canyon Natural Gas Storage Facility.

2. The CAISO was not provided the specific details of contracted procurement volumes for 13.5 MW of distribution-connected batteries at the time the cases were being prepared, so representative units in the area were modeled.

Mr. Alaywan takes exception to the batteries not being listed in Appendix A of the 2018-2019 CAISO Transmission Plan. The listings in Appendix A refer specifically to "Generation." Pumped storage has traditionally been included on the Existing Generation tables as those facilities are essentially generators that also have pumping capability. Therefore, the CAISO included the 40 MW associated with the Lake Hodges Pumped Storage Unit in Appendix A. By contrast, the CAISO has not included battery and other preferred resources such as demand response (existing and forecasted) in Appendix A, but rather discussed those resources in each relevant subsection of chapter 2 of the 2018-2019 CAISO Transmission Plan, along with the discussions of load forecasts and other parameters relevant to the specific planning region being discussed.

Consistent with this approach, the volume of batteries that the CAISO relied upon in conducting its reliability analysis for the San Diego area was identified in chapter 2 of the 2018-2019 CAISO Transmission Plan together with other preferred resources such as demand response (which were similarly not included in Appendix A).

Moreover, with respect to the power flow base cases themselves, and the batteries not being dispatched in those base cases, as I already explained in my rebuttal testimony,[2] the 2018-2019 Transmission Planning Process Unified Planning Assumptions and Study Plan ("2018-2019 Unified Planning Assumptions") set out how the CAISO would treat batteries in its studies, *i.e.*, that battery capacity would be dispatched off in the base cases and only dispatched as capacity as a mitigation once a reliability concern is identified. As stated therein:

> "The portion of authorized local capacity derived from *energy limited preferred resources such as demand response and battery storage* will be modeled offline in the initial base cases and will be used as mitigation once reliability concerns are identified." [emphasis added][3]

Therefore, the fact that only 40 MW of storage resources (representing pumped storage capacity) were shown as dispatched in the CAISO's power flow base cases also does not support Nevada Hydro's conclusion that there will not be additional battery capacity available to the CAISO in the area.

Q. Mr. Alaywan notes on Page 4 of his rebuttal testimony that the total generation capacity listed in Table 2.9-1 of the 2018-2019 ISO Transmission Plan shows less total installed capacity than the ISO reported dispatching in several

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[2] Exhibit CAISO-4 at 4.

[3] 2018-2019 Unified Planning Assumptions at 26.

scenarios. Why is this the case?

A. The amount of installed generation listed in Table 2.9-1 of the 2018-2019 CAISO Transmission Plan reflects a reduction of 100 MW of installed capacity or 93.8 MW qualifying capacity from the amount of installed generation modeled in the CAISO's studies to reflect the retirement of several small generators. The CAISO learned of these unexpected retirements after the CAISO's models were developed and final reliability analysis was performed. These four units were modeled in the studies, based on the initial 2018-2019 transmission planning cases provided by San Diego Gas & Electric Company ("SDG&E") and the 2019 Net Qualifying Capacity used for Local Capacity Requirements ("LCR") technical study consistent with the 2018-2019 Unified Planning Assumptions:

Table 2: 2019 Generation Retirement in SDG&E Area

Bus Name	Bus #	ID	Qualifying Capacity in MW
NAVALSTN QF	22560	1	30.4
NAVALSTN QF	22560	2	4
NAVALTRNG QF	22566	1	16.7
NRTH ISLD QF	22574	1	42.7
Total			**93.8**

The CAISO cannot re-start studies at the end of an annual transmission planning cycle every time one parameter changes. The CAISO accounts for such changes in the next year's planning studies.

Nonetheless, the CAISO also conducted studies with this small amount of generation retired, which verified that these retirements did not materially affect the results or conclusions in the 2018-2019 CAISO Transmission Plan. This is addressed in more detail below.

Q. Mr. Alaywan states that he relied on the CAISO's published generation list to identify 915 MW of generation that the CAISO would curtail to relieve transmission overloads on the SDG&E system and claims that the CAISO identified no other generation that could be curtailed.[4] He indicates that he found "no more resources to drop or re-dispatch" and thus concluded that the system is 50 MW deficient.[5] How do you respond?

A. Mr. Alaywan fails to account for the full range of generator and other resource output adjustments available to the CAISO to address potential contingencies in the San Diego area. To explain the generation adjustments and the corresponding amounts of generation available to adjust at each stage of such a contingency, I will first review the sequence of events and corresponding adjustments that the CAISO studied, and identify the areas where Mr. Alaywan's steps appears to have diverged. In particular, it appears that Mr. Alaywan did not dispatch generation down in Arizona to reduce imports over Path 46 into California after the first contingency and to prepare the system for the possibility of the second, and it is not clear from his description if he also dispatched up the batteries and fast demand response in the Southern California Edison Company ("SCE") system as well as the batteries and fast demand response in the SDG&E system. Further, it appears he may have understood that the 915 MW of

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4 September 5 Reply at 5-6.

5 Exhibit NHI-13 at 3.

thermal generation in the Imperial Valley area that is operated by the remedial action scheme in the area coincident with the second contingency to be the generation available for manual adjustments between the first and second contingency. I have also included attachments to this sur-rebuttal testimony setting out in tabular form the power flow results and each stage of events described below, and power flow plots demonstrating those outcomes. This repeats some aspects of my earlier declaration and rebuttal testimony but is necessary to address Mr. Alaywan's claims.

At any point in time, the CAISO is required by North American Electric Reliability Corporation ("NERC") mandatory standards to operate the system to be ready to withstand "the next" contingency, and the CAISO performs its transmission planning accordingly. If resources are needed to prevent an overload following a first contingency, then they would need to be dispatched at all times that the load is at a level where the contingency could result in an overload, or in the alternative, be available to be operated by a remedial action scheme that would perform the adjustment automatically when the contingency occurs. When the overload is a "P6" contingency as defined by NERC, and triggered by the second of two contingencies, at least 30 minutes is available for operators to make adjustments after the first contingency, under NERC standards, in order to prepare for the next contingency.

Mr. Alaywan's sur-rebuttal testimony focuses on two cases from the 2018-2019 CAISO Transmission Plan: the 2023 Summer Peak case and the 2028 Summer Peak case. Further, he focuses on a specific contingency – the "P6" contingency, using NERC terminology – which is the loss of the ECO-Miguel 500 kV transmission line followed, after an opportunity for system readjustment, by the loss of one of the two

Suncrest-Sycamore 230 kV transmission lines. In studying these types of contingencies, the CAISO simulates the first contingency by applying it to the posted base cases. However, adjustments can be made after simulating the first contingency – providing they can be accomplished within 30 minutes – to prepare for the next contingency. Therefore, the CAISO does not reflect these types of adjustments in the CAISO's base case, which is the snapshot of the system before the first contingency. Also, generation dropping or other switching that can be performed by remedial action schemes that will be triggered by the second contingency do not have to be modeled *before* the second contingency occurs – they are modeled as occurring immediately upon the second contingency occurring. (For the contingencies that are pertinent to this case and the subject of this discussion, the remedial action schemes are only triggered by the second contingency.) The base cases are modeled with generation dispatched at levels that are reasonable, and secure – *i.e*. there are no overloaded elements, and it is expected that overloads would not occur following the first contingency.

The CAISO performed the following steps in its reliability analysis on those base cases for the "P6" contingency that Mr. Alaywan refers to – the loss of the ECO-Miguel 500kV line followed by the loss of either of the Sycamore-Suncrest 230 kV line:

1. The first step in the power flow analysis consists of simulating the first contingency, and confirming that this does not result in any overloads.
2. Then, adjustments that would be triggered by the first contingency are also made – which for the loss of the ECO-Miguel 500 kV circuit includes adjustments of the Imperial Valley phase shifting transformer.

Also, the system adjustments re-dispatching up or down various resources are made that operators would be called upon to make within the 30 minute window. These resource dispatch and curtailment adjustments were not modeled in the CAISO's initial reliability results – the "without mitigation results" that excluded mitigations posted in Appendix C of the 2018-2019 CAISO Transmission Plan, and demonstrate that the additional mitigations continue to be needed. These adjustments entail dispatching resources downstream of the potential overload to higher levels of output, and curtailing generation upstream of the potential constraint. The 2023 and 2028 base cases already reflected gas-fired generation at its maximum output, so no additional gas-fired generation in the area was available for the CAISO to dispatch to higher levels in the San Diego area. However, the referred resources – consisting of fast response demand response – and battery storage described in chapter 2 of the 2018-2019 CAISO Transmission Plan in the SDG&E and SCE areas were available and dispatched up accordingly – totaling 998 MW in the 2023 Summer Peak case and 1022 MW in the 2028 Summer Peak case. These resources include the 161 MW of battery storage in the SDG&E area discussed earlier. Table 3 below sets out the volume of additional preferred resources dispatched after the first contingency to prepare for the second contingency.

Note that generation that may be tripped off by remedial action schemes following the second contingency would not be dispatched off before the second contingency is simulated – it can be held back so that it only trips if the second contingency actually occurs. Thus, the 915 MW of gas-fired generation in the Imperial Valley area that is connected to a remedial action scheme that would operate and trip the generation in the event of the second contingency was not manually dispatched down ahead of the second contingency, and instead is tripped coincident with the second contingency.

To maintain overall supply/demand balance in the power flow case while resources in the San Diego and SCE areas are dispatched up, about 998 MW and 1022 MW of generation in the Arizona Public Service Company ("APS") area – in Arizona – that would otherwise flow on the transmission lines into the San Diego area was curtailed for the 2023 Summer Peak case and the 2028 Summer Peak case, respectively. This reduces the amount of imported energy into the CAISO balancing authority area, reducing flows over Path 46 into southeastern California. Table 4 below sets out the generation in Arizona adjusted downward to maintain supply/demand balance and reduce imports over Path 46. This generation is separate and distinct from the 915 MW of Imperial Valley area gas-fired generation referenced by Mr. Alaywan and that is tripped by the remedial action scheme after the second contingency.

Table 3: Additional Preferred Resources and Batteries Available for Operational Mitigation Dispatch (after first contingency)

Study Case ID	Description	Preferred Resources in SDGE		Preferred Resources in SCE		Additional PR available for dispatch as part of System adjustment
		Fast Demand Response (MW)	Energy Storage (MW)	Fast Demand Response (MW)	Energy Storage (MW)	
B2-23SP	2023 Summer Peak Load	16	161	436	385	998
B3-28SP	2028 Summer Peak Load	16	161	436	409	1022

Table 4: Generation dispatched down as Operational Mitigation after First Contingency

Bus Name	Bus #	Unit ID	Area	Generation MW output before and after the System adjustment			
				B2-23SP 2023 Summer Peak Case		B3-28SP 2028 Summer Peak Case	
				prior to System adjustment	after System adjustment	prior to System adjustment	after System adjustment
15164	MES-CT1	1	APS (Area 14)	145	82	150	0
15165	MES-CT2	1		145	0	150	0
15166	MES-ST1	1		250	0	290	0
15167	MES-CT3	1		145	0	160	0
15168	MES-CT4	1		145	0	160	0
15169	MES-ST2	1		250	0	370	258
Sub-total				**1080**	**82**	**1280**	**258**
Total gen adjustment in MW					**998**		**1022**
15982	NAVAJO 2	1		PSLF swing bus picks up the transmission loss difference			

3. The second contingency is then simulated. As part of this step, remedial action scheme operation was simulated as that operation is automatic,

shedding the 915 MW of gas-fired generation connected to the remedial action scheme. This resulted in flow conditions that were within 30 minute emergency ratings, but not within long term ratings. Generation also has to be dispatched up immediately to compensate for the loss of the generation shed by the remedial action scheme – which initially occurs in real time on governor response from the generation fleet. Here, I need to draw attention to a detail regarding the modeling software used to prepare the power flow plots in this sur-rebuttal testimony. The CAISO used PSLF software to reproduce the 2018-2019 Transmission Plan results and prepare the attached power flow plots, and used TARA software to produce the results tabulated the 2018-2019 CAISO Transmission Plan itself.[6] As the two programs produce immaterial but perceptible differences at one stage based on how resources are dispatched to make up for the tripping of 915 MW through the remedial action scheme, the CAISO has performed this step here for both the 2023 and 2028 Summer Peak cases using both software tools, so that stakeholders can reconcile the result with tabulated results provided in the 2018-2019 CAISO

[6] The CAISO's tabulated results in the 2018-2019 CAISO Transmission Plan were developed using Transmission Adequacy & Reliability Assessment (TARA) software. TARA software provides a great deal of efficiency in running a large number of power flow contingency simulations and filtering and tabulating results, which is very important to the CAISO in conducting its power flow analysis of its entire system in the course of each annual transmission planning cycle. The PSLF power flow software is also used by the CAISO – and many of our stakeholders – in more localized studies and was more convenient for producing the power flow plots that I have included as attachments to this sur-rebuttal testimony. (The appendices are described in more detail below.) The two programs provide consistent results with one minor variation being how the generation making up the lost 915 MW is selected following the tripping of the generation through the operation of the contingency file – PSLF makes up the generation from one larger swing bus, whereas TARA distributes the incremental output across a broader range of generators. While the differences are not material, both sets of results were provided here so that the results can be reconciled precisely with the 2018-2019 CAISO Transmission Plan tabulated results.

Transmission Plan. Table 5 below sets out the 915 MW that was tripped via the remedial action scheme coincident with the second contingency.

Table 5: Generation Shedding via Remedial Action Scheme

Bus Name	Bus #	Unit ID	PMAX (MW)
22981	IV GEN1 STG	1	308
22982	IV GEN1 CTG2	1	172
22983	IV GEN1 CTG3	1	172
22996	INTBST	1	158.9
22997	INTBCT	1	193.5
Total PMAX			**1004.4**
Qualifying capacity (MW)			**915**

4. A final operator-action mitigation step was then simulated in the cases showing the effectiveness of the mitigations, but not simulated in the "without mitigations" simulations to demonstrate the need for the mitigation. This step consisted of further adjustments to the settings of the Imperial Valley phase shifting transformer, which can readily be accomplished in much less than 30 minutes, to reduce flows from levels below the 30 minute rating to flows that are below the long term ratings of the transmission system.

Power flow plots have been attached to this sur-rebuttal testimony for each stage of the sequence discussed above, for the following three scenarios based on the 2018-2019 transmission planning cycle posted base cases:

1. Attachment A: The above contingency simulation steps applied to the posted 2023 and 2028 Summer Peak base cases but *without* any

resource adjustment steps described in step 2, or the adjustments described in step 4. This case demonstrates the need for these mitigations, and match the tabulated reliability results set out on page 1 of 7 of the San Diego Main Study Area pre-mitigation results in Appendix C of the 2018-2019 CAISO Transmission Plan.

2. Attachment B: The above contingency simulation steps taken exactly as set out in steps 1 through 4 above, including resource adjustment mitigations in step 2 and the further actions set out in step 4. These results demonstrate the effectiveness of these mitigations – which are in place.

3. Attachment C: The effectiveness of the mitigations was demonstrated by repeating all of steps 1 through 4 on modified base cases. The posted base cases were modified to retire the Naval Station gas-fired generation (100 MW installed capacity, 93.8 MW qualifying capacity) that had retired after the 2018-2019 transmission planning studies had been completed, and also to correct an erroneous dispatch of 100 MW to 0 MW of a generator at bus 22789 (Q189GEN2) in the 2028 Summer Peak case. These results demonstrate that the mitigations remain effective taking into account the retirement of the Naval Station generation in both summer peak cases and the correction to the 2028 Summer Peak dispatch.

Further, Attachment D provides two tables tabulating the results of the above power flow analysis:

- Attachment D – Table 1: Step by step tabulation of the posted base case analysis results at each step of the contingency analysis, *without and with all mitigations*, for both the 2023 Summer Peak and 2028 Summer Peak cases. (Includes the TARA-generated sensitivity that aligns with 2018-2019 CAISO Transmission Plan Appendix C tabulated results).

- Attachment D – Table 2: Step by step tabulation of the results from the posted base cases adjusted by retiring the Naval Station generation (100 MW installed capacity, 93.8 MW qualifying capacity) for both the 2023 Summer Peak and 2028 Summer Peak cases and correcting an erroneous dispatch of Q189GEN2 at bus in the 2028 Summer Peak Case, *with all currently in place mitigations*. These results demonstrate that the in place mitigations continue to be effective and adequate after making these changes.

Q. Based on this explanation, where did Mr. Alaywan go wrong in his analysis of the 2023 and 2028 Summer Peak cases, and his conclusion that the CAISO would be deficient by 50 MW?

A. Mr. Alaywan referred to only finding 915 MW of generation in the Imperial Valley area available to dispatch to a lower level or off as an adjustment between the first and second contingency. He appears to be referring to the 915 MW of thermal generation identified in the contingency file that the CAISO posted, and that I have listed in Table 5 above[7]. That thermal generation can be operated by the remedial action scheme

[7] There is also solar generation in the Imperial Valley area that can be tripped by the remedial action scheme or re-dispatch, but solar output would be zero at the time the 2023 and 2028 Summer

coincident with the second contingency; it would not have to be dispatched down after the first contingency in preparation for a potential second contingency. He did not take into account reducing imports over Path 46 from Arizona by reducing generation in APS, which would be performed by operator action after the first contingency to prepare for the second. That generation is listed in Table 4 above. This generation is not identified in the CAISO's contingency files because the contingency files only identify automated responses, not manual dispatch steps.

Q. Mr. Alaywan also states that your "claim" about batteries or other resources being available to solve the contingency or the outage problem is not backed up by any study that CAISO has produced, and indeed conflicts with the information that the CAISO has made publicly available. Do you agree?

A. No. To the contrary, the CAISO has made this information available through a combination of documentation in the 2018-2019 transmission planning process, including the 2018-2019 Unified Planning Assumptions, the 2018-2019 CAISO Transmission Plan, planning process documents posted on the CAISO website (including presentations at stakeholder meetings), and the posted cases and contingency files made available to stakeholders via the CAISO's market participant portal. Consistent with practices employed for many years, the CAISO's study results are tabulated and presented to stakeholders through stakeholder processes including

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Peak base cases are modeling, as those peaks occur in the early evening after solar output is no longer available. The contingency files on which Mr. Alaywan solely relied show 1,963 MW of wind and solar resources that also can be tripped under the remedial action scheme, but that is only relevant to off-peak cases during which there is solar generation output.

presentation of the draft plan, and the cases and contingency files are available for stakeholders with the appropriate tools to replicate any results of particular interest. The study results presented in my testimony and attachments are not new – except for the additional studies testing of the effects of the retirement of the Naval Station Generation that took place after the original studies were completed and a correction to the 2028 Summer Peak case. Further, to prepare this testimony the results were replicated primarily using PSLF software so intermediate results could be plotted, and stakeholders could replicate the results themselves using the more commonly-used PSLF software.

Q. Mr. Alaywan states that because the time when contingencies will occur cannot be predicted, that there is no way to know whether the batteries will be available to relieve the contingency. He also claims that the CAISO's position conflicts with the information that it has made publicly available.

A. I have already addressed the second issue regarding battery data, in both in my rebuttal testimony and above, so I will not repeat it a third time. Mr. Alaywan was simply looking in the wrong place for the data.

Mr. Alaywan is correct that the actual time when contingencies may occur cannot be predicted. However, load levels – and the associated potential for overloads if the "worst" contingencies occur at the "worst" possible time – can be forecast. In planning to rely on batteries – or other use-limited resources such as demand response – the CAISO must forecast the amount of time the system would be at risk of potential overload based on daily load shape information, and ensure that the use-limited resources have sufficient capacity and energy to reduce loading such that if the first contingency occurs immediately before the high load period, the risk of an overload is mitigated in the event the second contingency occurs. These considerations have received particular attention in the course of approving two battery storage projects in the 2017-2018 CAISO Transmission Plan as transmission assets. Further, Appendix G: 2028 Local Capacity Technical Study ("Appendix G") to the 2018-2019 CAISO Transmission Plan provides detailed information on load shapes supporting the consideration of energy requirements in large part to enable the analysis necessary to ensure that use-limited resources will meet reliability needs.

The status of the CAISO's efforts to enhance our ability to utilize preferred resources – including use-limited resources such as demand response and batteries, was discussed in sections 1.1.2 and 1.2.3 of the 2018-2019 CAISO Transmission Plan, and references to ongoing policy initiatives are provided in that document.

Economic Issues

Q. Mr. Alaywan refers to the incremental negative 132 million net load payment value that the CAISO's production cost study calculated for LEAPS as "a cost to load of $132 million as a result of LEAPS' relieving curtailments," and claims that the "CAISO's negative $132 million estimate is attributable to current curtailment conditions…"[8] Is Mr. Alaywan correct?

A. No. Mr. Alaywan's testimony that the negative $132 million net load payment

[8] Exhibit NHI-13 at 6-7.

"comes from curtailment" is over-broad and incorrect[9] as it attributes the entire load payment value to one factor that is but one influence on the amount of net load payment. Mr. Alaywan erroneously takes my earlier observation that the steepness of the supply price curve in the range of negative prices was a contributing factor to the magnitude of the $132 million increase in load payments resulting from the addition of LEAPS to the market as confirmation of his view that the "cost to load that the CAISO calculated comes from curtailments."[10] Mr. Alaywan's mischaracterization of the CAISO's production cost simulation results is best addressed by reiterating what the CAISO's studies actually do, and then clarifying where Mr. Alaywan mischaracterizes the results.

The CAISO's economic planning assessments are based on two production cost simulation results, both seeking to achieve the lowest overall production costs – one simulation with, and one simulation without, the project being studied. The production cost study is performed using a nodal analysis, with transmission constraints taken into account. The locational marginal prices ("LMP") at each node set the revenue for generation and the cost to load, and while those prices may be consistent across the system if there is no congestion, they also may differ based on the existence of transmission constraints. Generally, LMPs will increase in load pockets where transmission constraints drive the need to increase the output of more expensive generation in the load pocket rather than being able to transmit more lower cost

9 Exhibit NHI-13 at 7. Mr. Alaywan incorrectly takes my earlier observation that the steepness of the supply price curve in the range of negative prices was a contributing factor to the magnitude of the $132 million increase in load payments to market as confirmation that the "cost to load that the CAISO calculated came from curtailments."

10 Exhibit NHI-13 at 7.

generation from outside the constrained area, and LMPs will generally decrease in generation pockets, where transmission limitations prevent exporting that generation to serve load outside of the pocket.

As I summarized in my initial declaration (beginning on page 34, attached to the CAISO's July 22, 2019 Answer to Complaint, and my rebuttal testimony ("Exhibit CAISO-4") in particular beginning on page 7 attached to the CAISO's August 21, 2019 reply, the CAISO's production simulation results are then tabulated to assess impacts; by considering the increase in "load payments" (the summation of LMPs multiplied by the volume of load at each node), changes in generation revenues (derived from LMPs and the volume of generation output) and changes in transmission revenues resulting from wheeling fees or congestion revenue rights.[11] The production simulation itself does not set out to determine a sum of only "congestion benefits" or "curtailment benefits" of a particular transmission addition, but rather, assesses all benefits whether congestion-related or market-driven without being impacted by congestion. When adding a transmission line – that changes flow patterns on the network – the benefits generally relate to congestion or line losses. When considering the addition of a pumped storage facility, the impacts on congestion are just one facet of the changes being measured. The impacts of charging at a particular time of the day, which changes generation levels and flow patterns to serve the pumping load, and discharging or generating at a different time, which also affect other generators and flow patterns, both contribute to the costs and benefits of such a project. The upward pressure on LMP, and the corresponding increase on load payments, has the same effect if LMPs

[11] Exhibit CAISO-4 at 7.

move from one negative value to a "less negative" value as if they moved by the same dollar amount from a positive number to a larger positive number. (Negative prices generally occur when curtailment is taking place, but the pumped storage is not restricting from pumping during low cost hours when prices may still be positive.) Further, if the upward pressure on LMP from charging is at a time when there is little transmission congestion, the LMP increase may be felt by most of the ISO footprint, whereas the downward pressure on LMP from generating may be at a time where due to transmission congestion, the high LMPs being pushed down are only being felt by a small load pocket. The relative magnitude of the step changes is also important, of course, as well as knowing which generators are in or out of the load pocket and if their benefits accrue to ratepayers.

In summary, Mr. Alaywan's statement that the negative $132 million in net load payment that the CAISO calculated for LEAPS is solely the product of LEAPS' impact on generator curtailments is overly simplistic and fails to account for the full scope of the CAISO's production cost simulation, which again, considers all of the impacts that a project such as LEAPS will have on CAISO ratepayers, regardless of whether they relate to changes in generator curtailments, congestion patterns, or other costs that accrue to CAISO ratepayers.

Q. How do you respond to Mr. Alaywan's claims that the CAISO "inappropriately treated the transmission benefit of LEAPS as a detriment" and "if energy storage to relieve the over-generation problem increases the cost to

load by making prices less *negative*, it would never be economic"?[12]

A. This is untrue. The production cost analysis results provide estimates of all of the benefits resulting from LEAPS by considering all of the impacts on load payments into the market and any generation and transmission revenues accruing back to CAISO ratepayers, (i.e. load customers). But, it must also consider the offsetting impact the charging of the pumped storage has on increasing prices paid by load in the market, and that may not all flow back to generators whose benefits accrue to ratepayers.

Mr. Alaywan appears to ignore that increased load (pumping load) *would* in fact increase LMPs when the pumped storage facility is charging.

Moreover, as the CAISO's production simulation results demonstrated in the 2018-2019 CAISO Transmission Plan show the increase in load payment resulting from adding LEAPS was offset with other revenues that accrue to ratepayers, resulting in overall market cost savings and net production simulation benefits to ratepayers – just not sufficient to offset the capital costs of LEAPS, which are currently projected at $2 billion. Lower cost projects providing similar benefits would have a better chance of demonstrating a positive benefit-to-cost ratio.

For generators with a power purchase agreement ("PPA"), the benefits of receiving higher revenues stemming from higher LMPs are returned to load customers through the true-up provisions of the PPA; those true-up provisions are also expected to shield generators from the risk of curtailment. When the "true-up" of revenues is taken into account in the CAISO's analysis, LEAPS produces economic benefits to ratepayers as demonstrated in the overall results of the CAISO's production cost analysis – just not

12 Exhibit NHI-13 at 7.

sufficient to outweigh the annual impact of LEAPS' capital cost.

Q. Mr. Alaywan testifies that the CAISO has not factored into its analysis the price reconciliation associated with PPAs and this leads to distorted results because decreasing curtailments is always a benefit to load.[13] Do you agree?

A. PPAs, or utility ownership, play a critical role in determining which benefits of higher LMPs – or reduced curtailment – received by generators flow back to load customers. As I discussed earlier, rising LMPs initially trigger higher load payments into the market, and higher revenues received by generators. Under the CAISO's transmission economic assessment methodology ("TEAM"), PPA's based on contracts for differences lead to the return of excess market revenues to load if prices are high, and shortfalls are recovered from load if LMPs are low. However, when studying the incremental impact of a transmission addition, the actual strike price in the PPA is not relevant because it remains constant both before and after the addition of the transmission facility – and the CAISO is looking at the incremental revenue being returned with and without the project being studied. TEAM looks at the incremental changes to LMPs (and revenues) and the specific units whose revenues are increasing (or decreasing) – *i.e.*, whether they are merchant units or PPA units/utility retained generation – compared to the production cost study without the new project. By studying the lowest cost overall dispatch, and tracking which generators are utility owned or under a PPA, the overall impacts to CAISO ratepayers are appropriately tracked and accounted for.

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[13] Exhibit NHI-13 at 13-14.

A simple example of comparing prices and settlements under a "with project" and "without project" production cost simulation can show the effect of one influence at a time. If the addition of a pumped storage project results in it charging in a particular hour and raising the LMP from the "without project" price of negative $25 to negative $15, the LMP price increase could be felt across much of the CAISO. The "load payment" calculation would reflect the increase in load payment of $10 multiplied by the amount of load, and generators would also see an increase in their revenues. However, any utility owned generator or generator under a PPA would ultimately return these additional revenues back to ratepayers. For example, a generator with a PPA price of $30 would have been receiving a $55 per MWh ($30 minus negative $25) true-up from the load through the settling of the contract for differences under the "without project" scenario, but only receives a $40 per MWh ($30 minus negative $10) settlement for the hour the storage was charging under the "with project" scenario. In both cases, the offsetting changes to market payments and settlements from the load keep the generator "whole" relative to its PPA price of $30 – in other words, the generator with the PPA is indifferent to the LMP settlement as it is ultimately resettled to just receiving its PPA price. Load payments into the market go up, and revenue from PPA-based generation offset to some degree based on how many generators have a PPA in place. However, the generators that are not under a PPA also see a $10 increase in LMP and do not return any of the increase in LMP to load, so the load is not shielded from the total effect of the LMP increase.

The opposite would occur later in the day at high load and high price periods, when the pumped storage is discharging and putting downward pressure on LMPs.

Those LMP reductions will reduce load payments into the market, which depending on the circumstances may or may not result in offsetting the higher load payment into the market resulting from the charging. Even if they do not offset the impact of charging, the consideration of incremental generation revenues returned to load through settlement of contract for difference arrangements will also offset some of the increased load payments into the market.

Regarding curtailment risk, the CAISO's analysis assumes the risk of curtailment to generators with PPAs is borne by load customers. For generators that are under a PPA, fixed price PPAs reflecting take or pay provisions that pass curtailment risk to the load customers are essentially a sunk cost to the load and do not change regardless of the addition of a new transmission facility. In other words, loads pay a price for a specified quantity of energy under the PPA whether or not production from the generator is curtailed, so it is essentially a sunk cost. The market impact on revenues based on production volumes and price differences do get reflected in the incremental differences between before- and after-production simulation studies. However, not all generators are under a PPA. It is therefore necessary to consider all of the impacts, including what other generation is affected by the curtailment and if the constraints are local creating "generation pockets" or if the negative prices are being experienced across the entire CAISO footprint. Further, the benefit of the pumped storage to load is from using low cost energy to pump – which may reduce curtailment, and returning that energy during high cost periods, not just from pumping.

Q. Mr. Alaywan points to the results from the 2018-2019 CAISO Transmission Plan for other projects, specifically; the North Gila-Imperial Valley #2 500 kV transmission line, and the proposed HVDC Conversion Project, claims that the fact that the results differed from LEAPS shows that CAISO did not use the same methods to study those transmission projects that it used to study LEAPS, and that the CAISO confused curtailment costs and benefits to the detriment of LEAPS.[14] How do you respond?

A. The ISO employed the same methods to study LEAPS as used to study these potential transmission projects in the 2018-2019 CAISO Transmission Plan – performing production simulations with and without each project and tabulating the benefits – per TEAM – that accrue to CAISO ratepayers. The results shown for the North Gila and HVDC Conversion projects cited by Mr. Alaywan differ from LEAPS primarily because – and here I must state the obvious – these are both transmission line projects, and not pumped storage units that must first be charged in order to supply energy later. As a result, neither the study of the North Gila-Imperial Valley #2 500 kV transmission line nor the study of the proposed HVDC Conversion Project involve consideration of the impact of charging on LMPs, and so the interactions between LMPs, load payments and generation revenues are different from LEAPS.

In the case of the two transmission line projects, the projects resulted in increased load payments, and varying impacts on generator revenues and transmission revenues. These results simply demonstrate that depending on location, a new transmission line can result in increasing system-wide load payments by redistributing

[14] Exhibit NHI-13 at 8.

flows over paths into a load pocket that actually drive up congestion along with the need for additional generation to be dispatched on the load side of the constraint. This can occur when the proposed new transmission line reduces impedances on a particular path into a load pocket that has thermal limitations downstream of the new transmission line, pulling flows from other paths into the same pocket coming in from different directions. This is not a new or undocumented phenomenon, as the CAISO has observed this multiple times with respect to proposed new transmission lines.

Regarding the proposed North Gila-Imperial Valley #2 500 kV transmission line, beside concerns expressed in the 2018-2019 CAISO Transmission Plan regarding increasing flows on a path that has downstream constraints,[15] the CAISO noted in the 2018-2019 CAISO Transmission Plan that since the 2014-2015 CAISO Transmission Plan, there has been a need to bypass series capacitors on the existing 500 kV lines already in this corridor (Sunrise and Southwest Power Link) to increase impedances and push power away from other upstream or downstream facilities to mitigate overloads[16]. Similarly, the CAISO observed that the HVDC Conversion Project increased congestion along the Suncrest to Sycamore corridor and on Path 26.[17] While these circumstances did not have the same degree of impact on load payments compared to the market impact of charging a pumped storage facility such as LEAPS, they nonetheless resulted in increases in load payments into the market. As with the study of any proposed economic driven transmission project, however, the offsetting revenue benefits from generators or transmission that return benefits to ratepayers must

[15] 2018-2019 CAISO Transmission Plan, Section 4.9.11.3 at 332.

[16] 2018-2019 CAISO Transmission Plan, Section 2.9.5 at 188.

[17] 2018-2019 CAISO Transmission Plan, Section 4.9.11.2 at 326.

be calculated to see the whole picture.

Mr. Alaywan's attempt to draw a direct correlation between the amount of total curtailment and the load payment component of the overall CAISO ratepayer benefit impact is overly simplistic and does not take into account the actual details of projected energy price curves, impacts of charging pumped storage for later generation, and the boundaries of load and generation pockets (which change at various load levels) as well as the distribution of merchant generation, utility owned generation, and generation that is have PPAs with load serving entities.

Q. Mr. Alaywan produced a value of avoided curtailments – an estimate of average pool price applied to 927 GWh – that he claims the CAISO's analysis overlooks.[18] How do you respond?

A. As I discussed above, the benefits of reducing renewable curtailment is one of the many factors in the CAISO's cumulative results from its TEAM analysis. Applying an average price to avoided curtailments ignores the all of the considerations I have discussed above regarding assessing the impacts of pumping and generating on the market, and tracking which generation and transmission benefits accrue to CAISO ratepayers.

[18] Exhibit NHI-13 at 9-10.

Attachment A

Power Flow Plots

Without Operational Mitigation Addressing the P6 SCR-SX Overload Concern

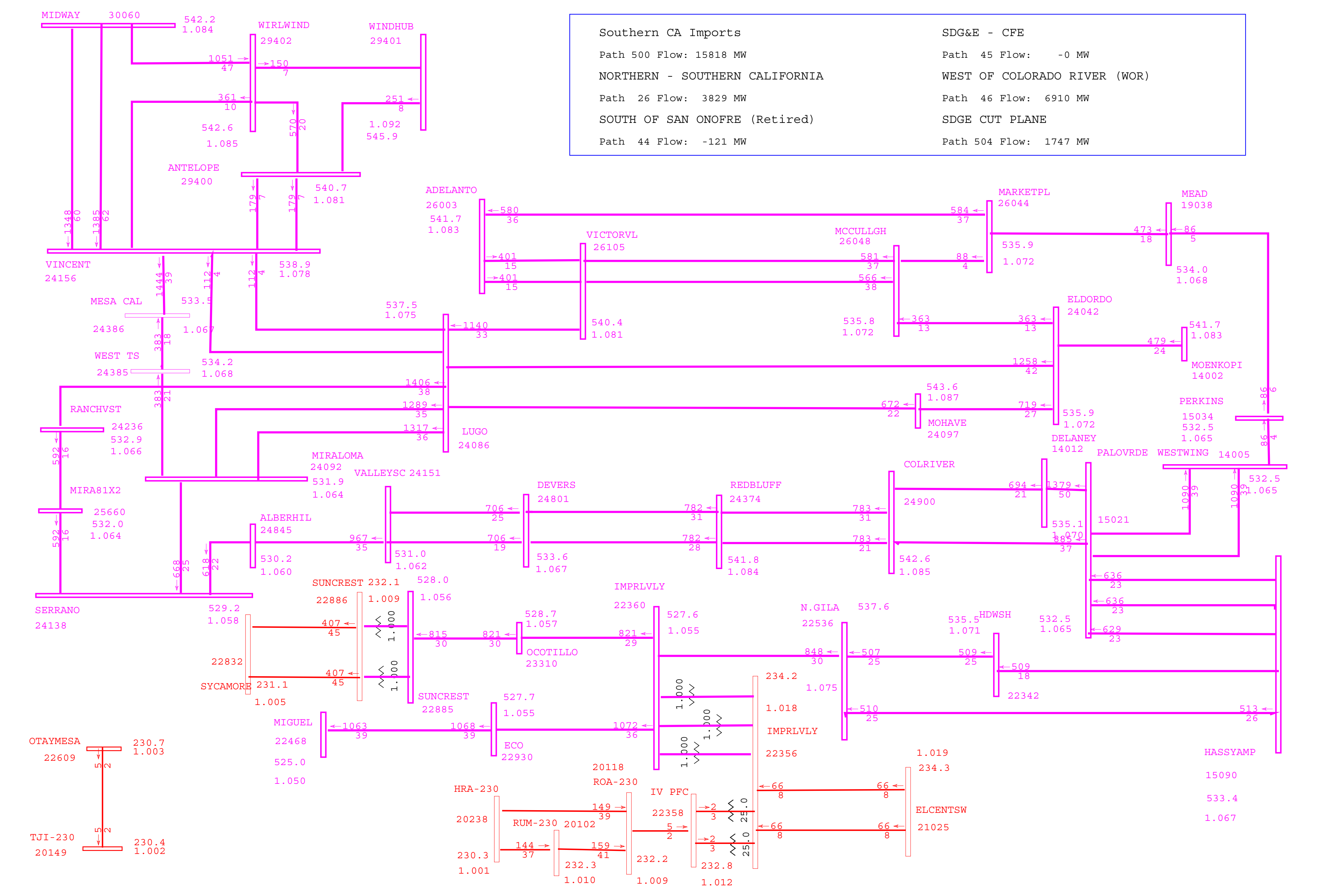
Based on the TPP 2018-19 TPP SDGE-Main Base Cases

2023 Summer Peak Base Case

- Figure 2N-GE_Step0
- Figure 2N-GE_Step1
- Figure 2N-GE_Step2
- Figure 2N-GE_Step3
- Figure 2N-TARA_Step3

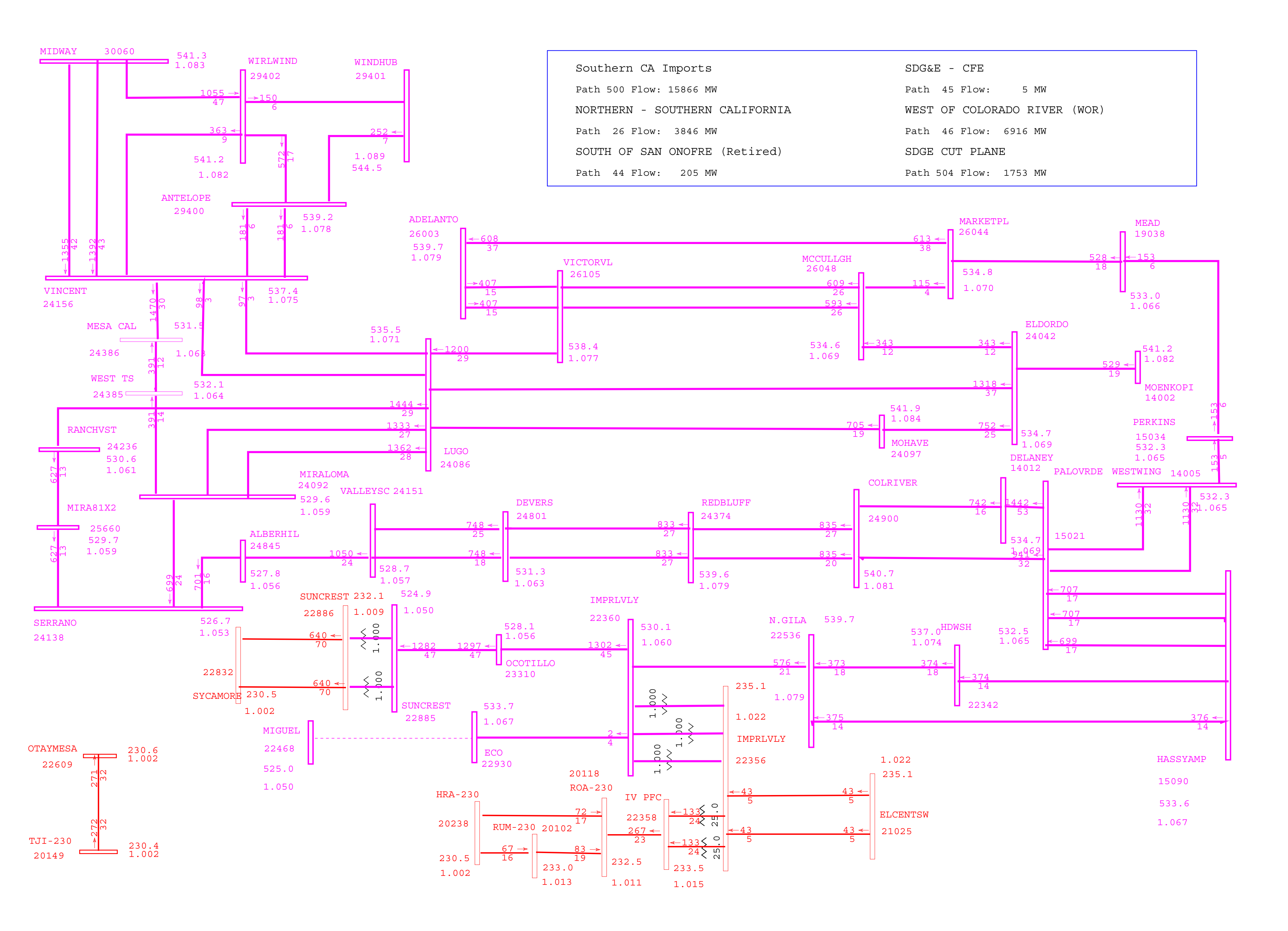
2028 Summer Peak Base Case

- Figure 3N-GE_Step0
- Figure 3N-GE_Step1
- Figure 3N-GE_Step2
- Figure 3N-GE_Step3
- Figure 3N-TARA_Step3



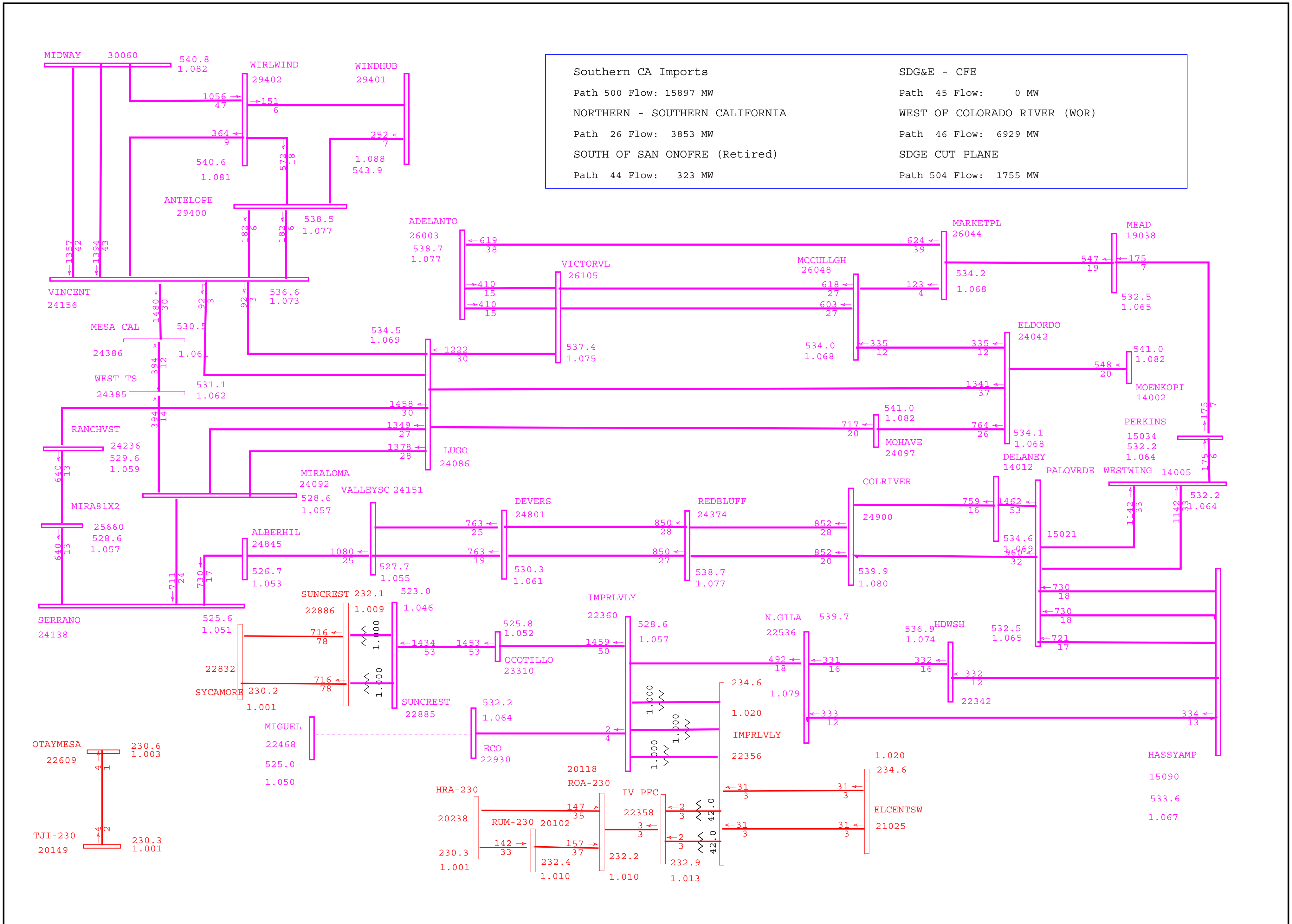
General Electric International, Inc. PSLF Program Fri Sep 13 13:09:30 2019 B2_SDGE-Main_2023SP_V1.sav

GE	WESTERN ELECTRICITY COORDINATING COUNCIL 2023 HS2a, July 19, 2017 TPP 2018-2019 SDGE-Main 2023SP Base Case	Figure 2N-GE_Step0: Initial Operating Condition For P0 no contingency (all Elements are in service)	MW/% rate SDGE_2019-V1.drw Rating = 1



General Electric International, Inc. PSLF Program Fri Sep 13 12:53:08 2019 2N-GE_Step1_B2_SDGE-Main_2023SP_V1.sav

WESTERN ELECTRICITY COORDINATING COUNCIL 2023 HS2a, July 19, 2017 TPP 2918-19 SDGE-Main 2023SP Base Case	Figure 2N-GE_Step1: Prior to adjusting IV-PST for the 1st P1 event of ECO-Miguel 500kV line	MW/% rate SDGE_2019-V1.drw Rating = 2



General Electric International, Inc. PSLF Program Fri Sep 13 12:56:45 2019 2N-GE_Step2_B2_SDGE-Main_2023SP_V1.sav

WESTERN ELECTRICITY COORDINATING COUNCIL 2023 HS2a, July 19, 2017 TPP 2018-2019 SDGE-Main 2023SP Base Case	Figure 2N-GE_Step2: After adjusting IV-PST for the 1st P1 event of ECO-Miguel 500kV line	MW/% rate SDGE_2019-V1.drw Rating = 2

Southern CA Imports

Path 500 Flow: 16791 MW

NORTHERN - SOUTHERN CALIFORNIA

Path 26 Flow: 3877 MW

SOUTH OF SAN ONOFRE (Retired)

Path 44 Flow: 693 MW

SDG&E - CFE

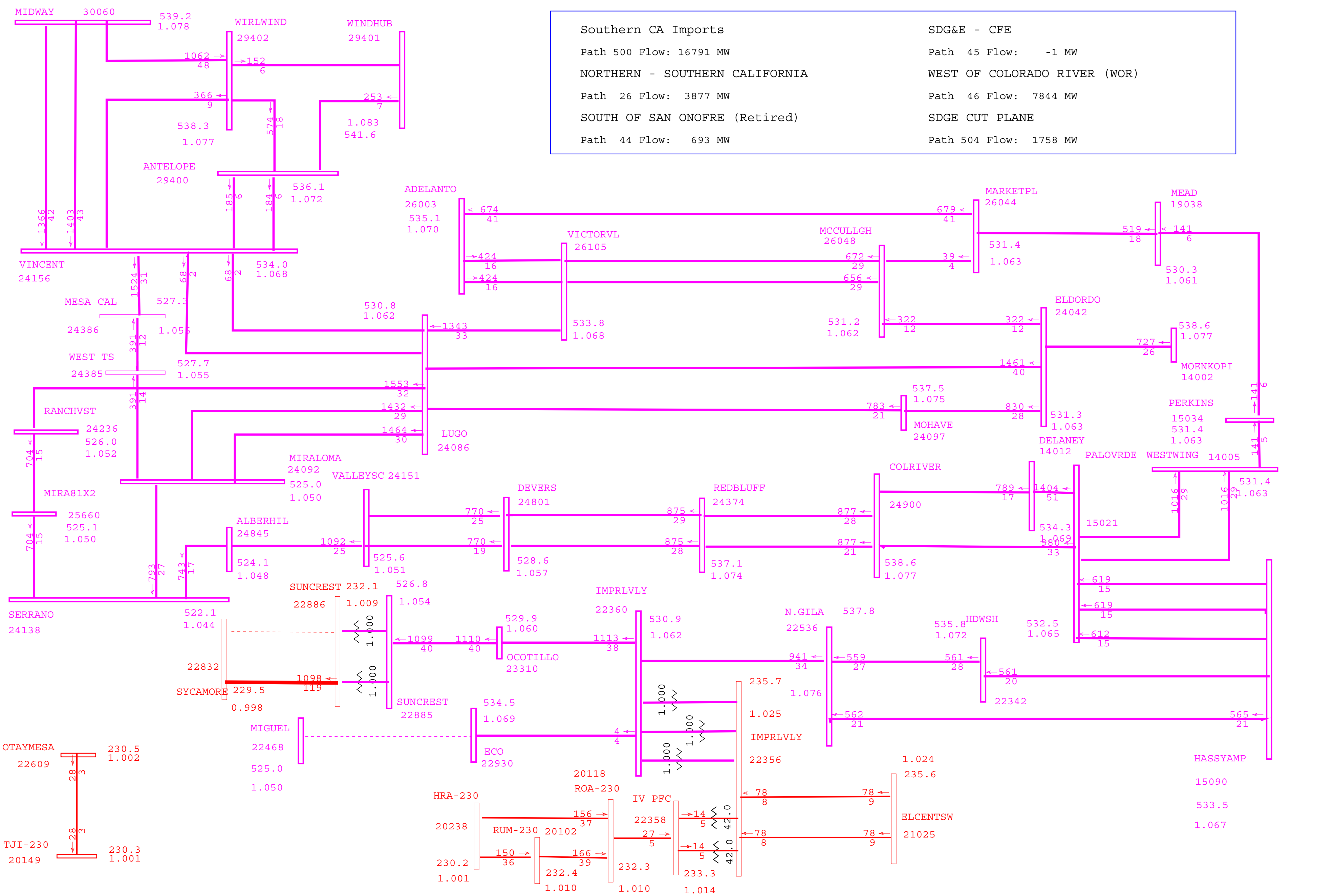
Path 45 Flow: -1 MW

WEST OF COLORADO RIVER (WOR)

Path 46 Flow: 7844 MW

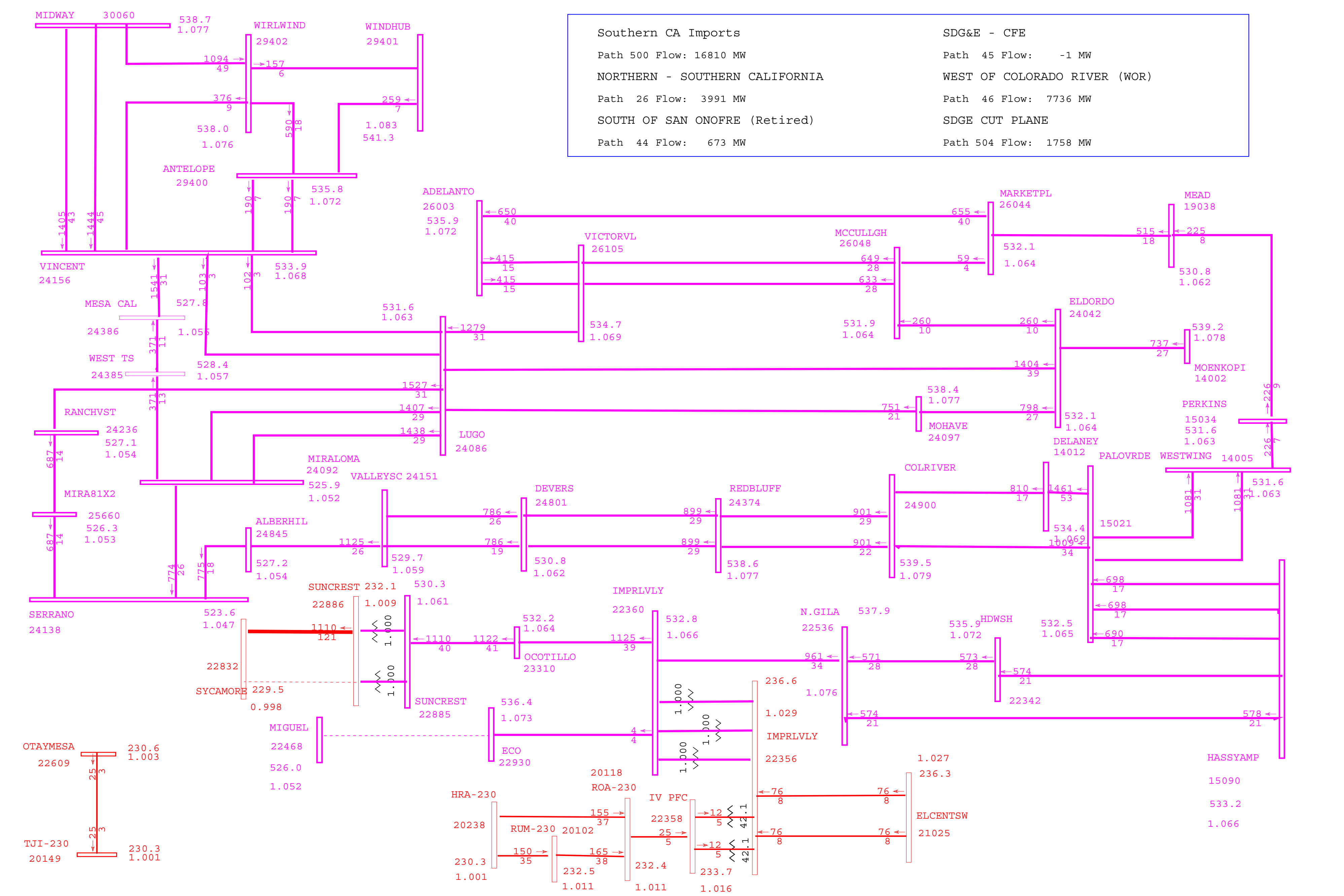
SDGE CUT PLANE

Path 504 Flow: 1758 MW



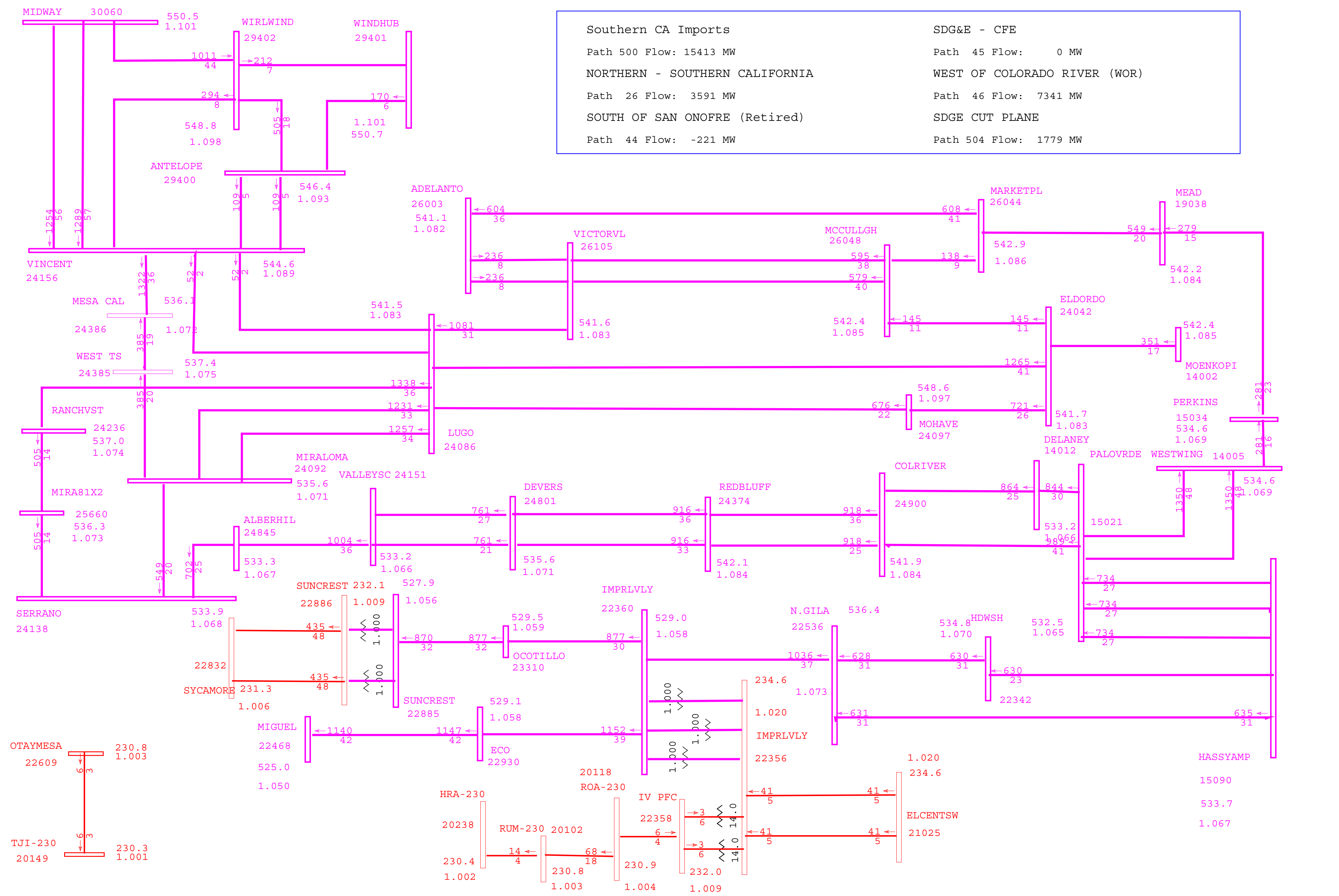
General Electric International, Inc. PSLF Program Fri Sep 13 12:57:13 2019 2N-GE_Step3_B2_SDGE-Main_2023SP_V1.sav

WESTERN ELECTRICITY COORDINATING COUNCIL 2023 HS2a, July 19, 2017 TPP 2918-19 SDGE-Main 2023SP Base Case (Simulation in GE-PSLF)	Figure 2N-GE_Step3: After the RAS action but prior to adjusting IV-PST for the 2nd P1 event of either of SCR-SX lines	MW/% rate SDGE_2019-V1.drw Rating = 2



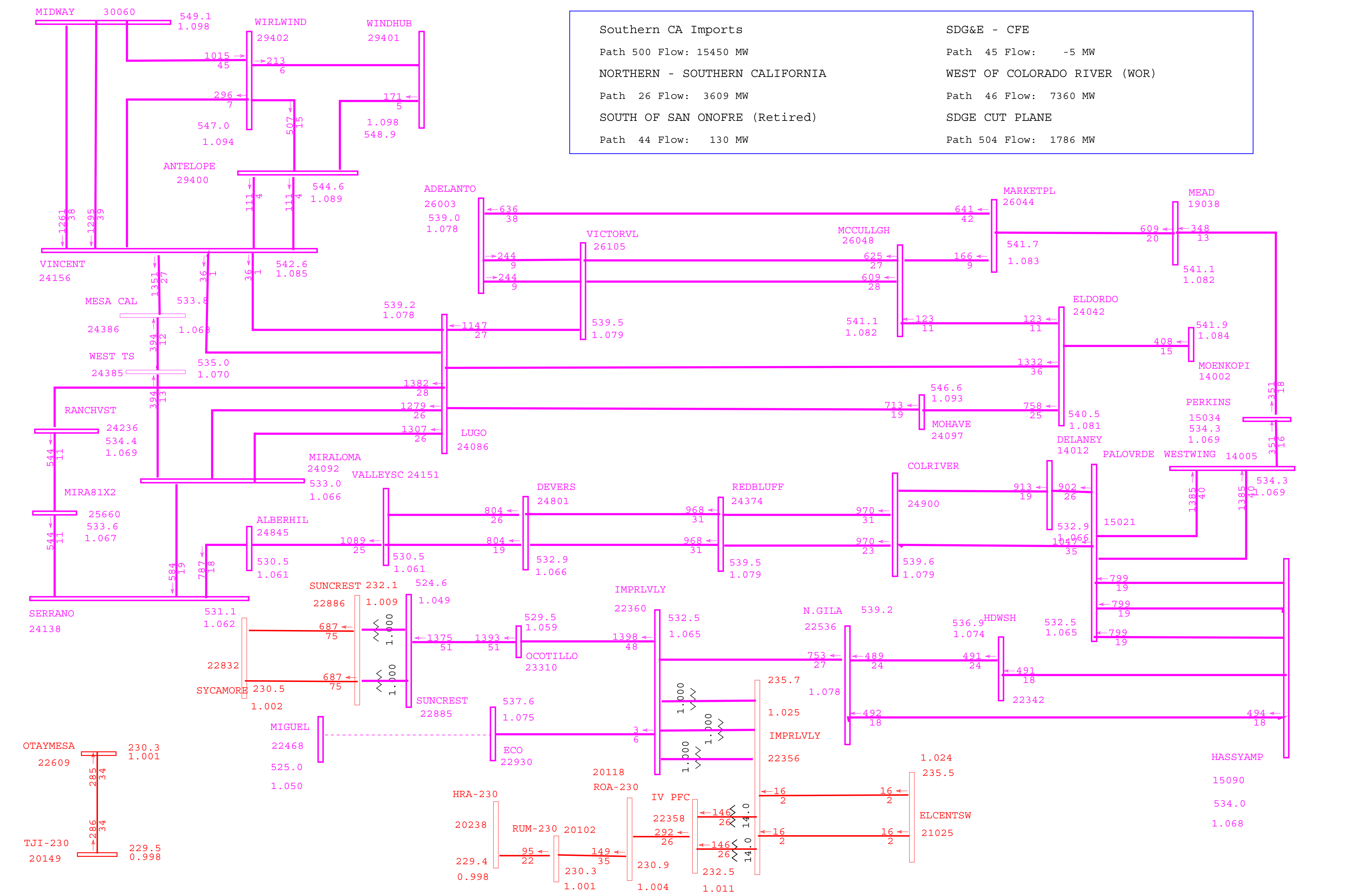
General Electric International, Inc. PSLF Program Fri Sep 13 13:24:22 2019 TARA_P6_P1_B2_SDGE-Main_2023SP_V1.sav

WESTERN ELECTRICITY COORDINATING COUNCIL 2023 HS2a, July 19, 2017 TPP 2018-2019 SDGE-Main 2023SP Base Case (Simulation in PowerGEM-TARA)	Figure 2N-TARA3_Step3: After the RAS action but prior to adjusting IV-PST for the 2nd P1 event of either of SCR-SX lines (Plot in GE-PSLF)	MW/% rate SDGE_2019-V1.drw Rating = 2



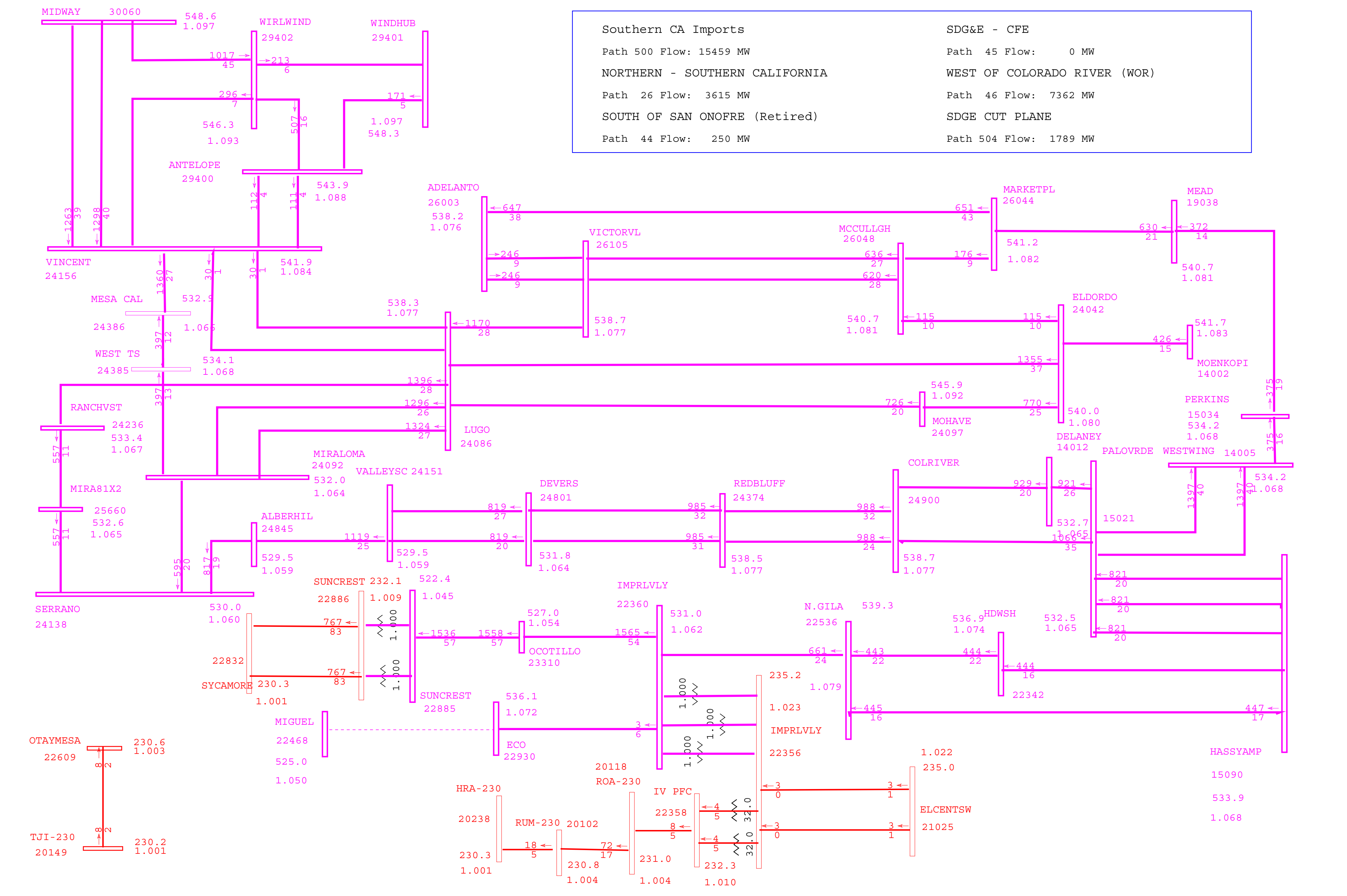
General Electric International, Inc. PSLF Program Fri Sep 13 13:10:17 2019 B3_SDGE-Main_2028SP_V1.sav

WESTERN ELECTRICITY COORDINATING COUNCIL 2028 HS1 ADS PLANNING CASE, DECEMBER 20, 2017 TPP 2018-2019 SDGE-Main 2028SP Base Case	Figure 3N-GE_Step0: Initial Operating Condition For P0 no contingency (all Elements are in service)	MW/% rate SDGE_2019-V1.drw Rating = 1



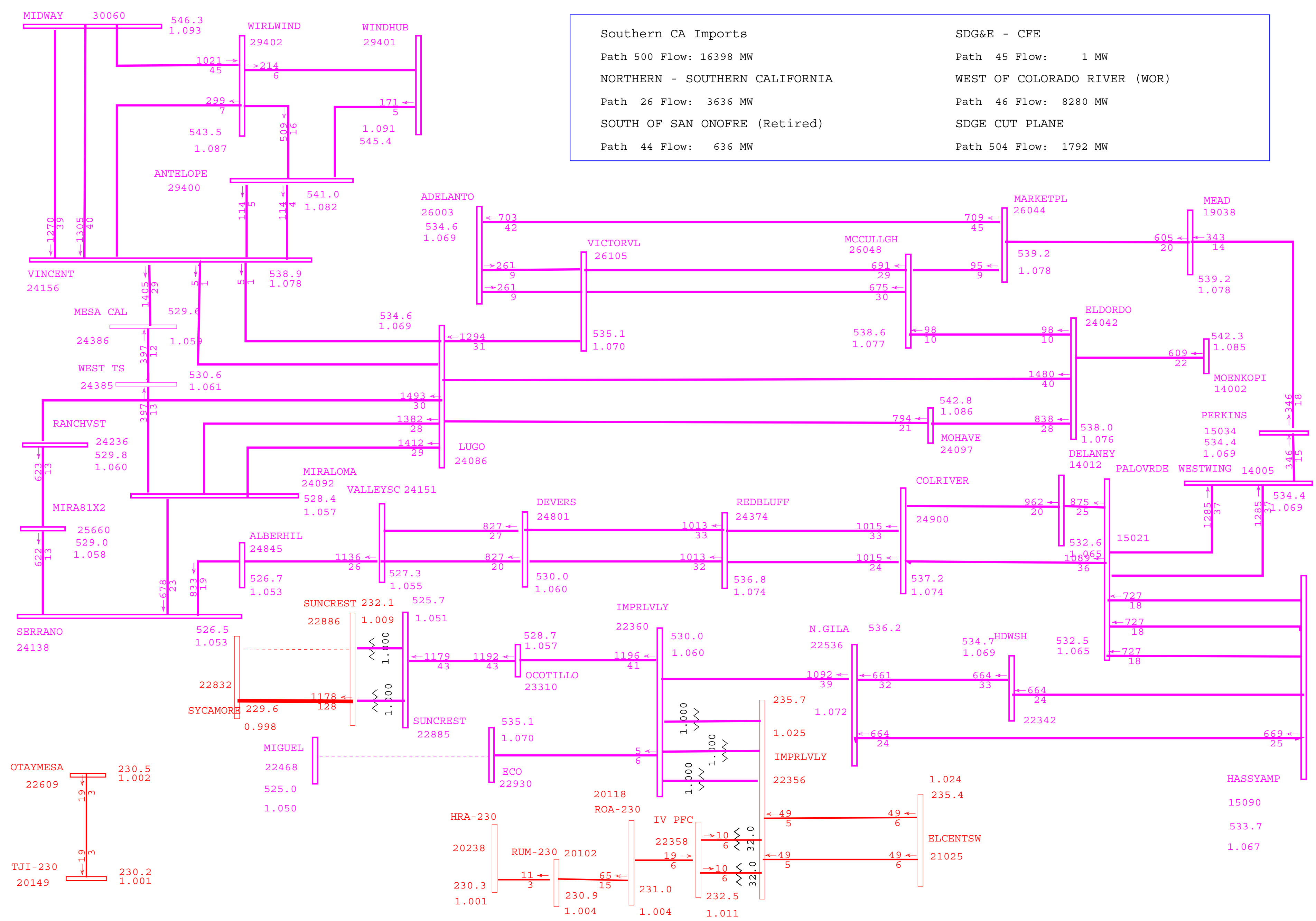
General Electric International, Inc. PSLF Program Fri Sep 13 13:02:00 2019 3N-GE_Step1_B3_SDGE-Main_2028SP_V1.sav

WESTERN ELECTRICITY COORDINATING COUNCIL 2028 HS1 ADS PLANNING CASE, DECEMBER 20, 2017 TPP 2018-2019 SDGE-Main 2028SP Base Case	Figure 3N-GE_Step1: Prior to adjusting IV-PST for the 1st P1 event of ECO-Miguel 500kV line	MW/% rate SDGE_2019-V1.drw Rating = 2



General Electric International, Inc. PSLF Program Fri Sep 13 13:03:09 2019 3N-GE_Step2_B3_SDGE-Main_2028SP_V1.sav

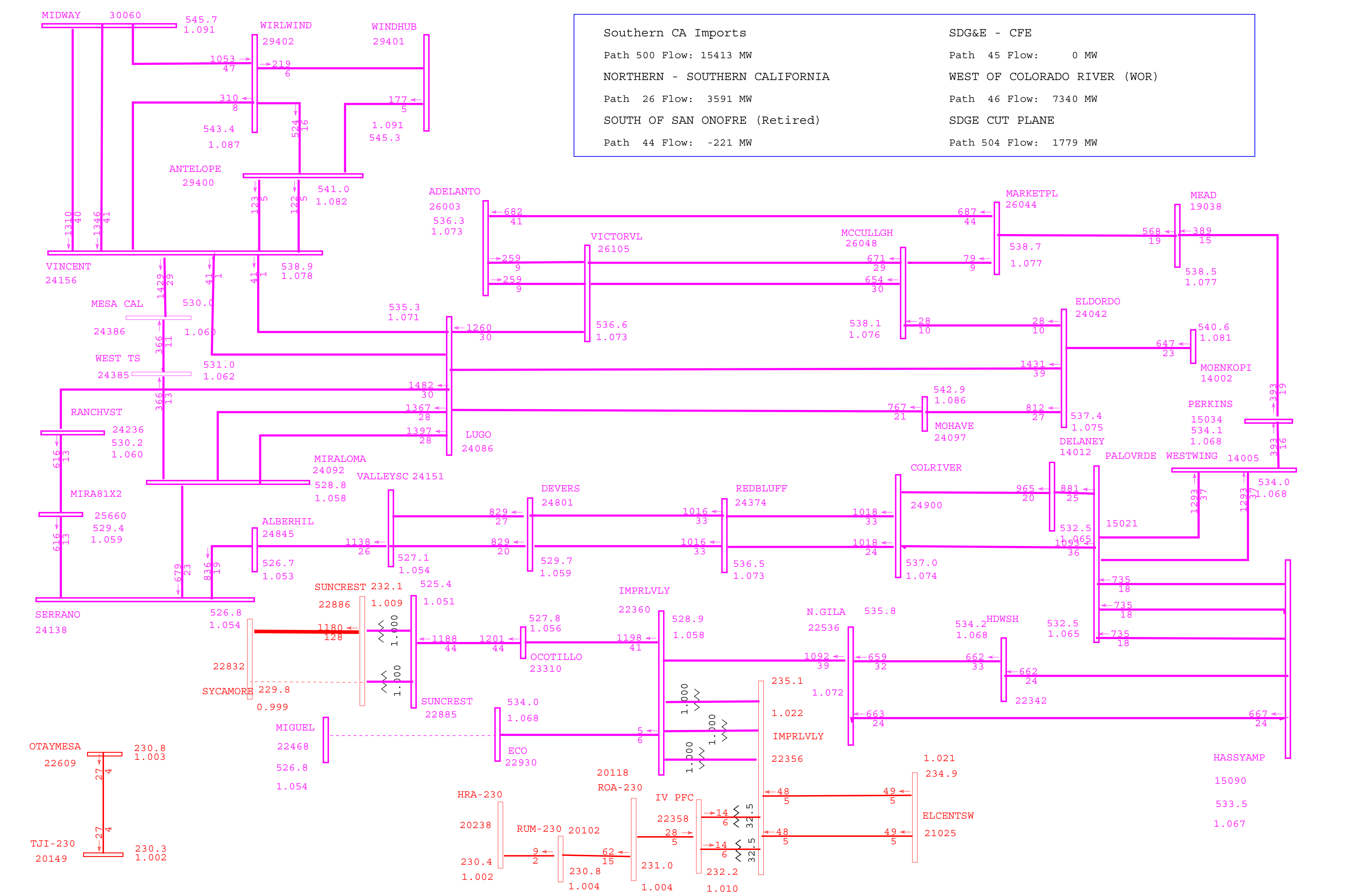
WESTERN ELECTRICITY COORDINATING COUNCIL 2028 HS1 ADS PLANNING CASE, DECEMBER 20, 2017 TPP 2018-2019 SDGE-Main 2028SP Base Case	Figure 3N-GE_Step2: After adjusting IV-PST for the 1st P1 event of ECO-Miguel 500KV line	MW/% rate SDGE_2019-V1.drw Rating = 2



General Electric International, Inc. PSLF Program Fri Sep 13 13:03:38 2019 3N-GE_Step3_B3_SDGE-Main_2028SP_V1.sav

	WESTERN ELECTRICITY COORDINATING COUNCIL 2028 HS1 ADS PLANNING CASE, DECEMBER 20, 2017 TPP 2918-19 SDGE-Main 2028SP Base Case (Simulation in GE-PSLF)	Figure 3N-GE_Step3: After the RAS action but prior to adjusting IV-PST for the 2nd P1 event of either of SCR-SX lines	MW/% rate SDGE_2019-V1.drw Rating = 2

Southern CA Imports	SDG&E - CFE
Path 500 Flow: 15413 MW	Path 45 Flow: 0 MW
NORTHERN - SOUTHERN CALIFORNIA	WEST OF COLORADO RIVER (WOR)
Path 26 Flow: 3591 MW	Path 46 Flow: 7340 MW
SOUTH OF SAN ONOFRE (Retired)	SDGE CUT PLANE
Path 44 Flow: -221 MW	Path 504 Flow: 1779 MW



General Electric International, Inc. PSLF Program Fri Sep 13 13:25:27 2019 TARA_P6_P1_B3_SDGE-Main_2028SP_V1.sav

WESTERN ELECTRICITY COORDINATING COUNCIL
2028 HS1 ADS PLANNING CASE, DECEMBER 20, 2017
TPP 2018-2019 SDGE-Main 2028SP Base Case (Simulation in PowerGEM-TARA)

Figure 3N-TARA3_Step3: After the RAS action but prior to adjusting IV-PST for the 2nd P1 event of either of SCR-SX lines (Plot in GE-PSLF)

MW/% rate
SDGE_2019-V1.drw
Rating = 2

Attachment B:

Power Flow Plots

With Operational Mitigation Addressing the P6 SCR-SX Overload Concern

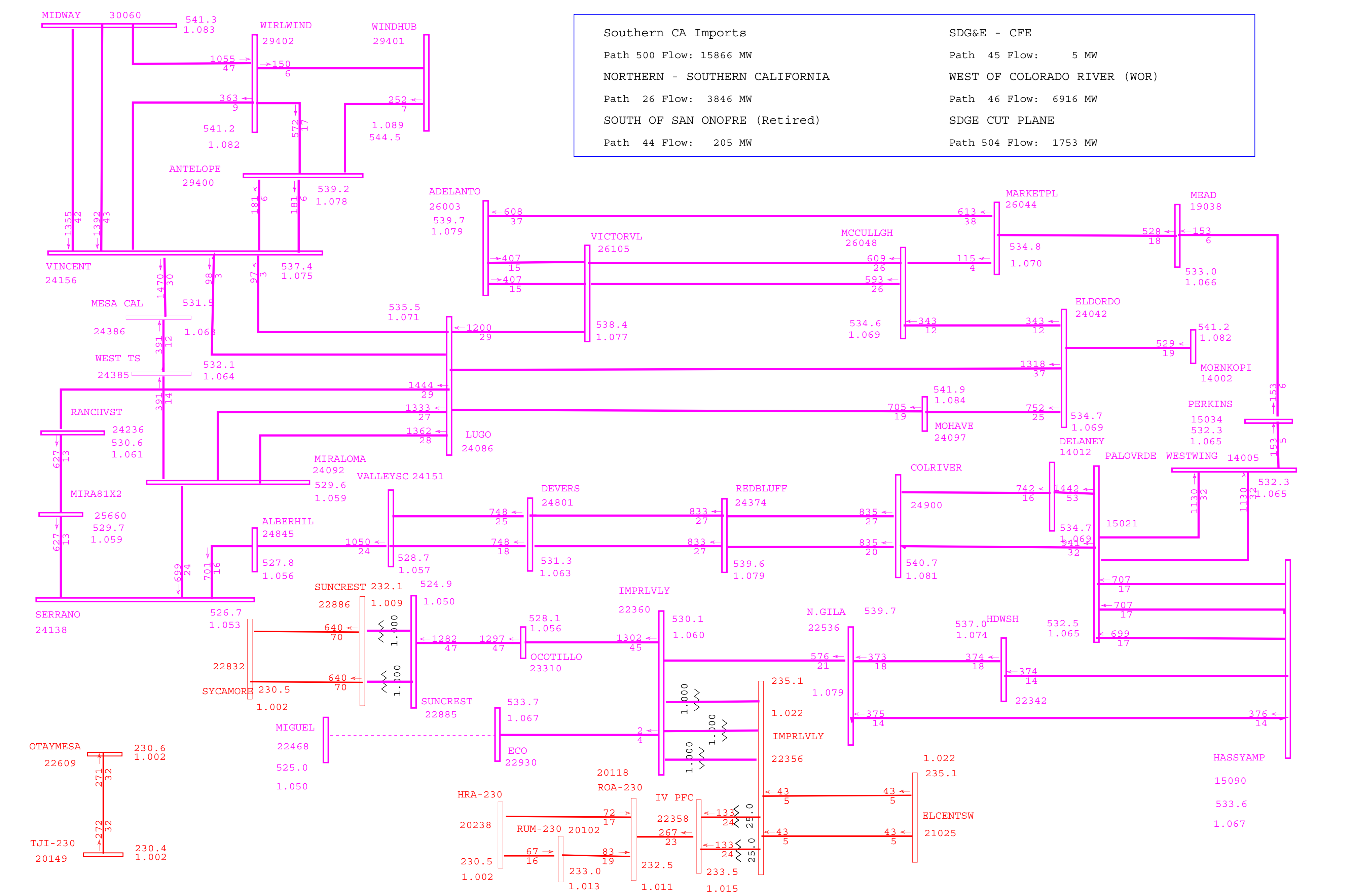
Based on the TPP 2018-19 TPP SDGE-Main Base Cases

2023 Summer Peak Base Case

- Figure 2Y-GE_Step1
- Figure 2Y-GE_Step2
- Figure 2Y-GE_Step3
- Figure 2Y-GE_Step4

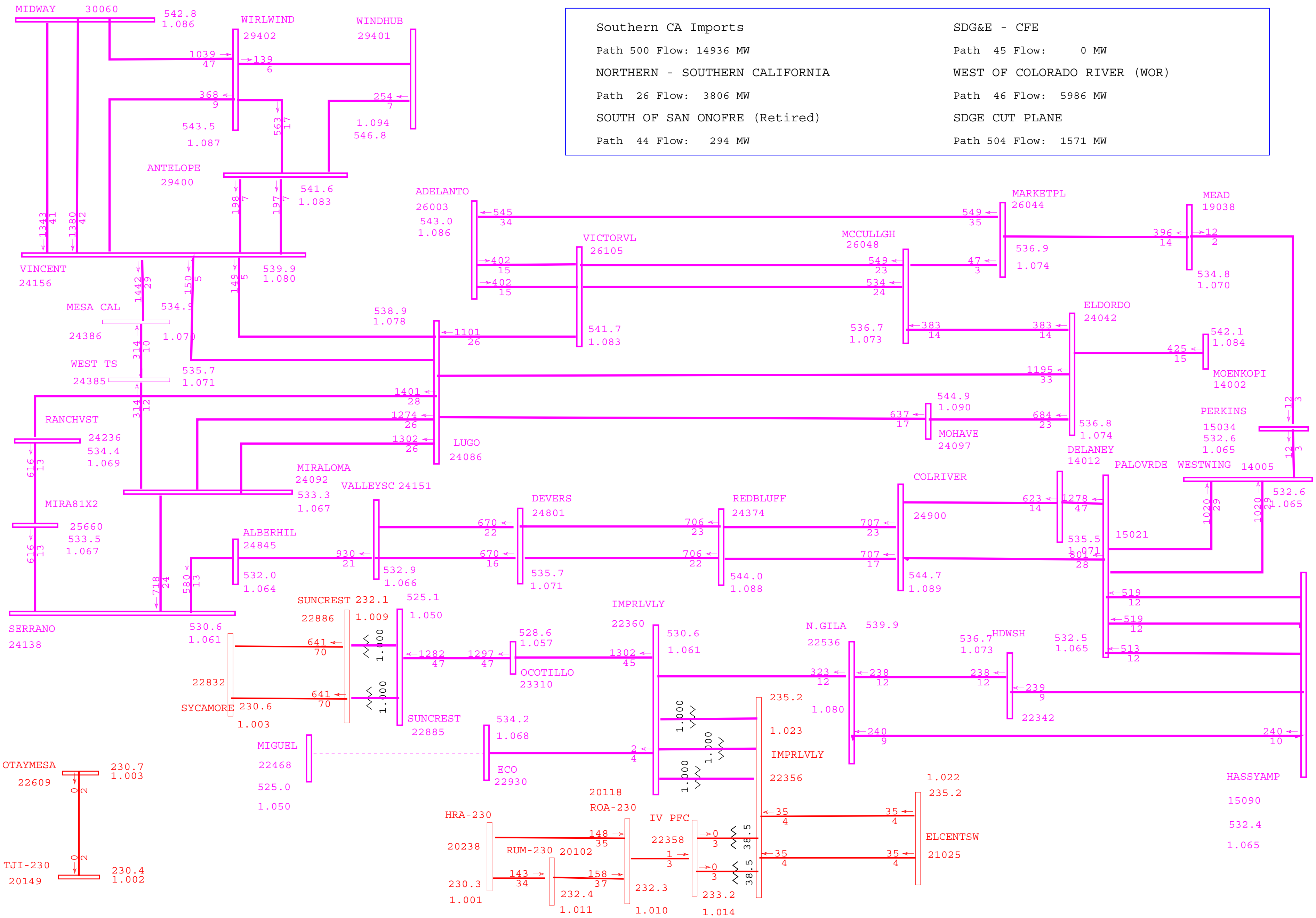
2028 Summer Peak Base Case

- Figure 3Y-GE_Step1
- Figure 3Y-GE_Step2
- Figure 3Y-GE_Step3
- Figure 3Y-GE_Step4



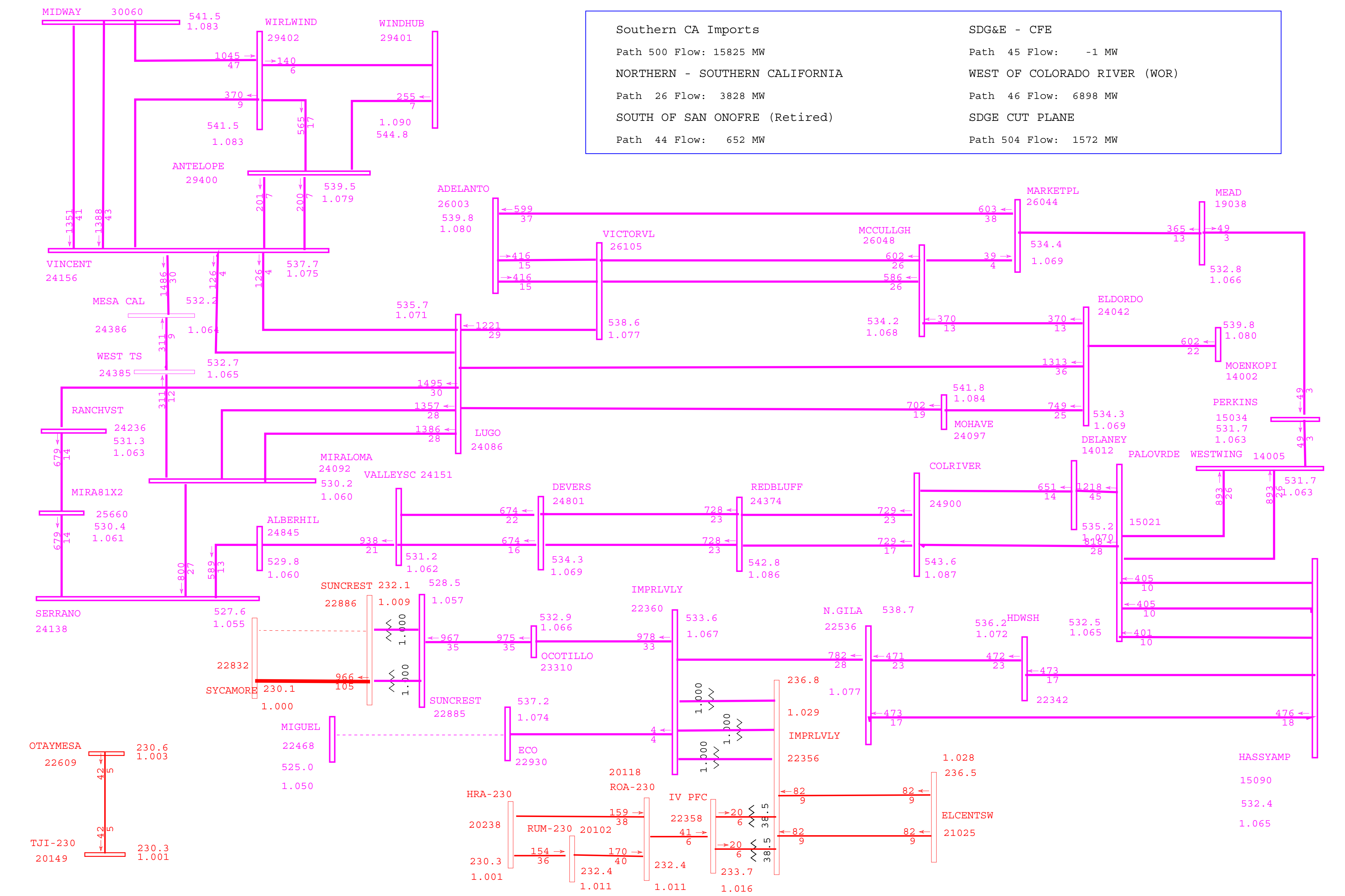
General Electric International, Inc. PSLF Program Fri Sep 13 12:58:13 2019 2Y-GE_Step1_B2_SDGE-Main_2023SP_V1.sav

	WESTERN ELECTRICITY COORDINATING COUNCIL 2023 HS2a, July 19, 2017 TPP 2018-2019 SDGE-Main 2023SP Base Case	Figure 2Y-GE_Step1: Prior to adjusting IV-PST for the 1st P1 event of ECO-Miguel 500kV line	MW/% rate SDGE_2019-V1.drw Rating = 2



General Electric International, Inc. PSLF Program Fri Sep 13 12:59:09 2019 2Y-GE_Step2_B2_SDGE-Main_2023SP_V1.sav

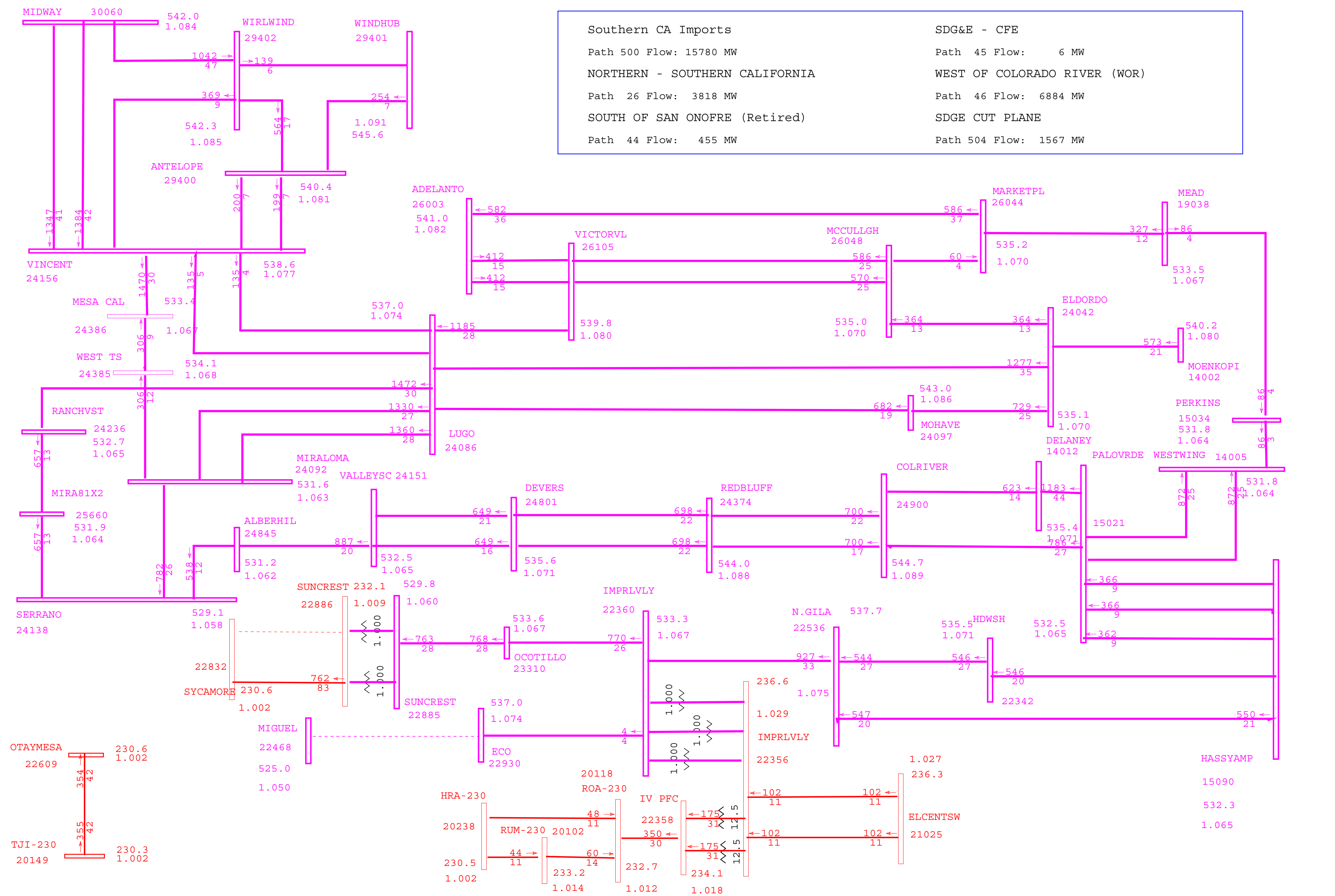
WESTERN ELECTRICITY COORDINATING COUNCIL 2023 HS2a, July 19, 2017 TPP 2018-2019 SDGE-Main 2023SP Base Case	Figure 2Y-GE_Step2: After adjusting System and IV-PST for the 1st P1 event of ECO-Miguel 500KV line	MW/% rate SDGE_2019-V1.drw Rating = 2



General Electric International, Inc.   PSLF Program   Fri Sep 13 13:00:57 2019   2Y-GE_Step3_B2_SDGE-Main_2023SP_V1.sav

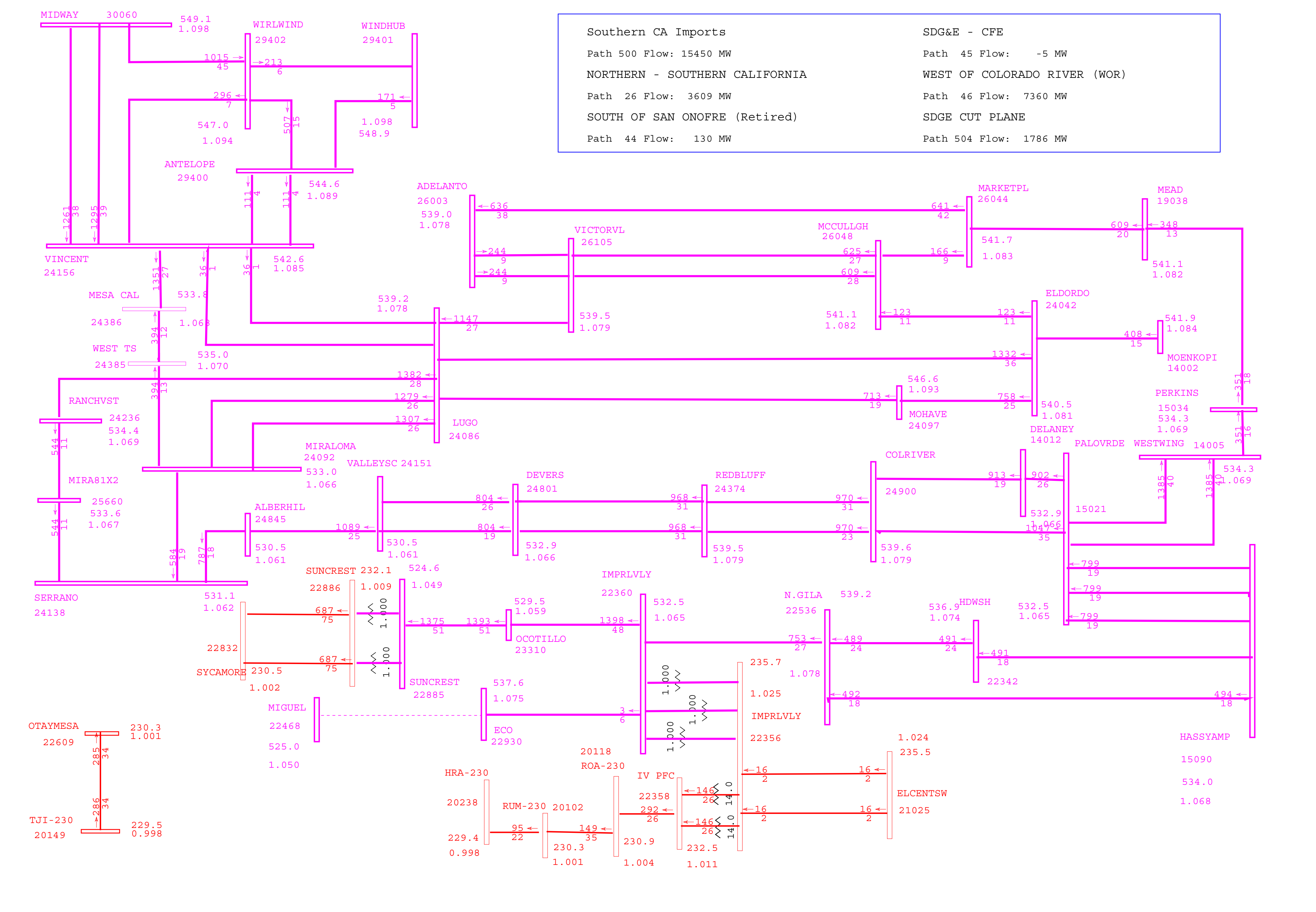
	WESTERN ELECTRICITY COORDINATING COUNCIL 2023 HS2a, July 19, 2017 TPP 2018-2019 SDGE-Main 2023SP Base Case	Figure 2Y-GE_Step3: After the RAS action but prior to adjusting IV-PST for the 2nd P1 event of either of SCR-SX lines	MW/% rate SDGE_2019-V1.drw Rating = 2

Southern CA Imports	SDG&E - CFE
Path 500 Flow: 15780 MW	Path 45 Flow: 6 MW
NORTHERN - SOUTHERN CALIFORNIA	WEST OF COLORADO RIVER (WOR)
Path 26 Flow: 3818 MW	Path 46 Flow: 6884 MW
SOUTH OF SAN ONOFRE (Retired)	SDGE CUT PLANE
Path 44 Flow: 455 MW	Path 504 Flow: 1567 MW



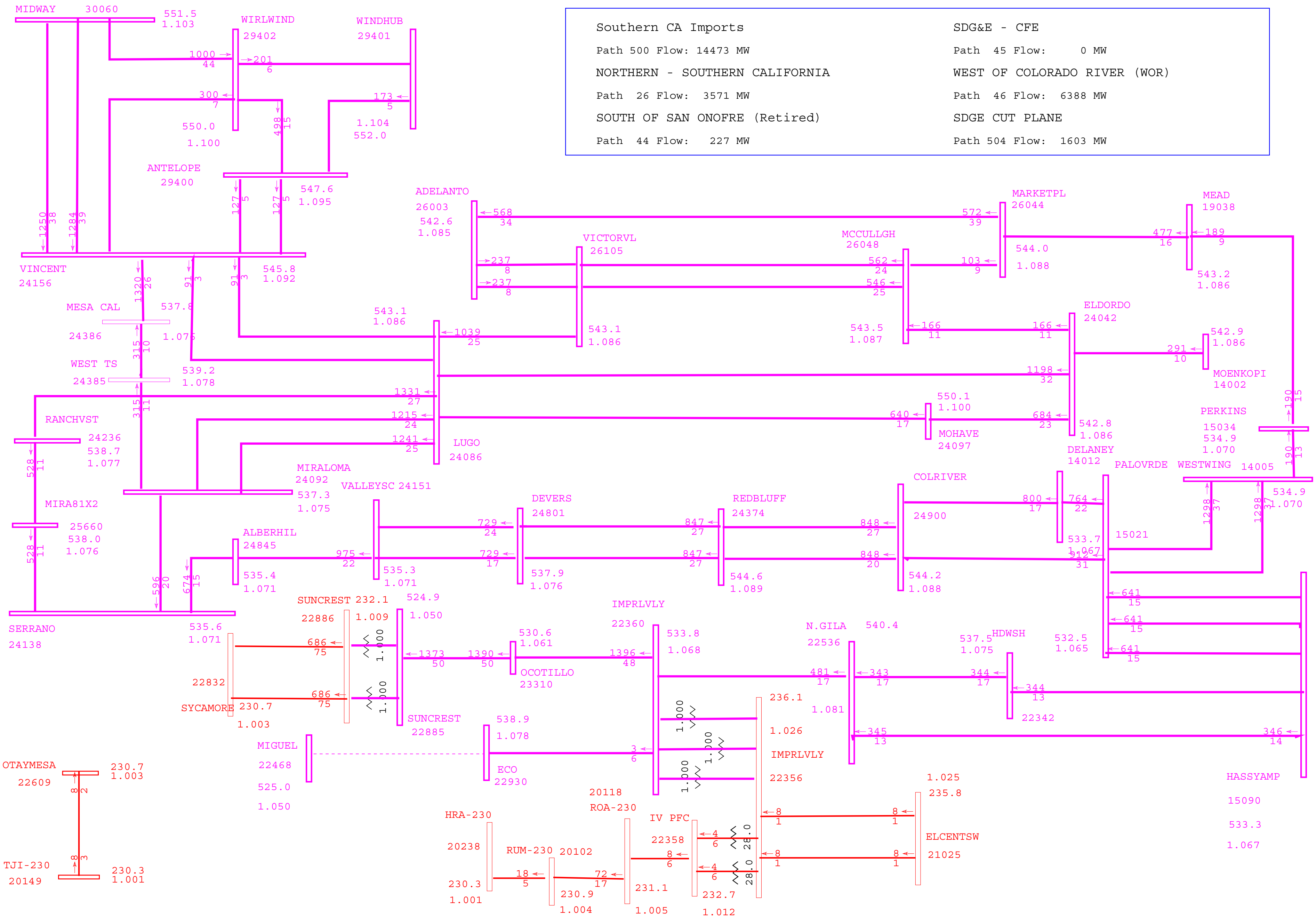
General Electric International, Inc. PSLF Program Fri Sep 13 13:01:30 2019 2Y-GE_Step4_B2_SDGE-Main_2023SP_V1.sav

	WESTERN ELECTRICITY COORDINATING COUNCIL 2023 HS2a, July 19, 2017 TPP 2018-2019 SDGE-Main 2023SP Base Case	Figure 2Y-GE_Step4: After adjusting IV-PST (350 MW via IV-PST) for the 2nd P1 event of either of SCR-SX lines	MW/% rate SDGE_2019-V1.drw Rating = 2



General Electric International, Inc. PSLF Program Fri Sep 13 13:04:33 2019 3Y-GE_Step1_B3_SDGE-Main_2028SP_V1.sav

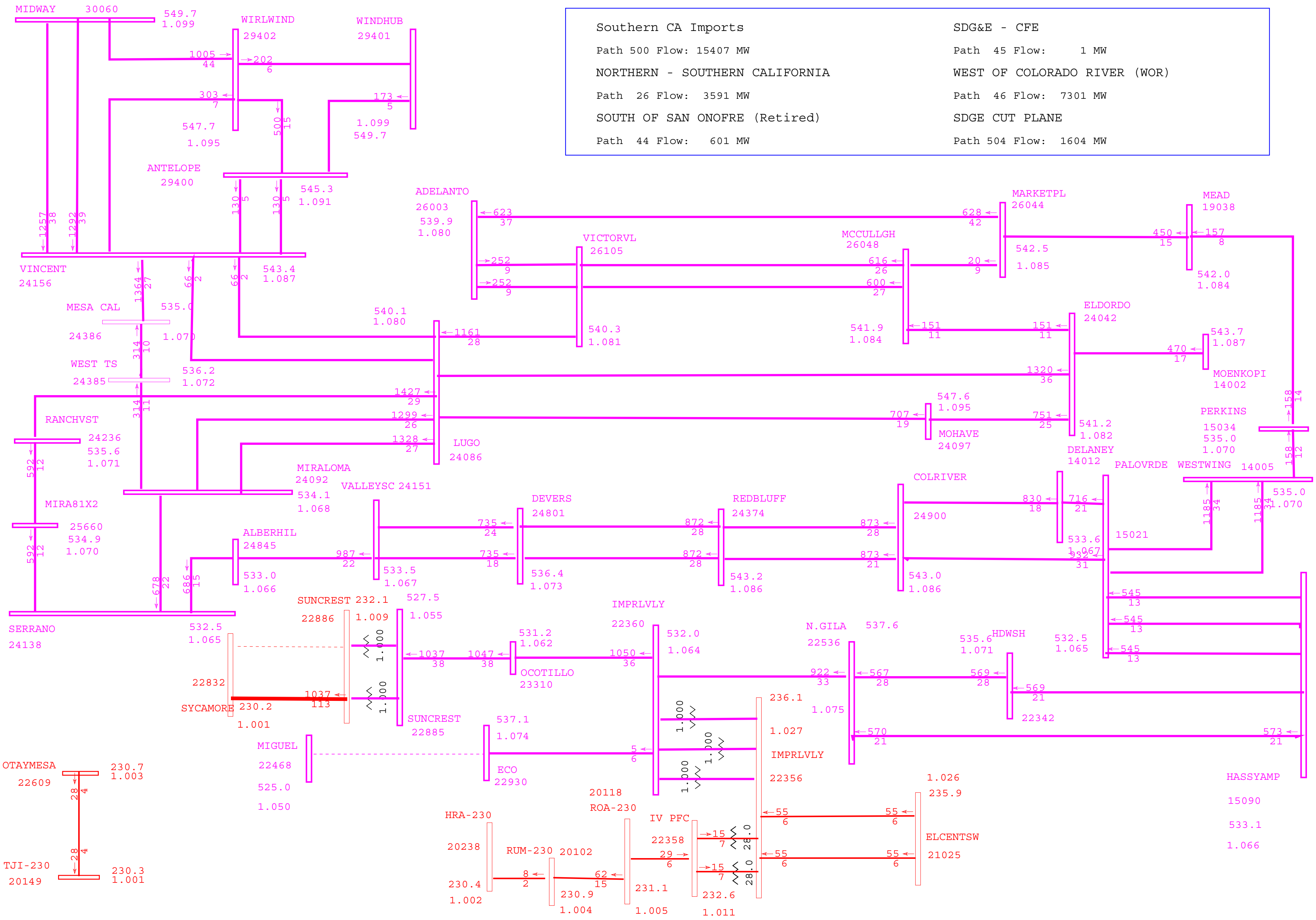
WESTERN ELECTRICITY COORDINATING COUNCIL 2028 HS1 ADS PLANNING CASE, DECEMBER 20, 2017 TPP 2018-2019 SDGE-Main 2028SP Base Case	Figure 3Y-GE_Step1: Prior to adjusting IV-PST for the 1st P1 event of ECO-Miguel 500kV line	MW/% rate SDGE_2019-V1.drw Rating = 2



General Electric International, Inc. PSLF Program Fri Sep 13 13:05:18 2019 3Y-GE_Step2_B3_SDGE-Main_2028SP_V1.sav

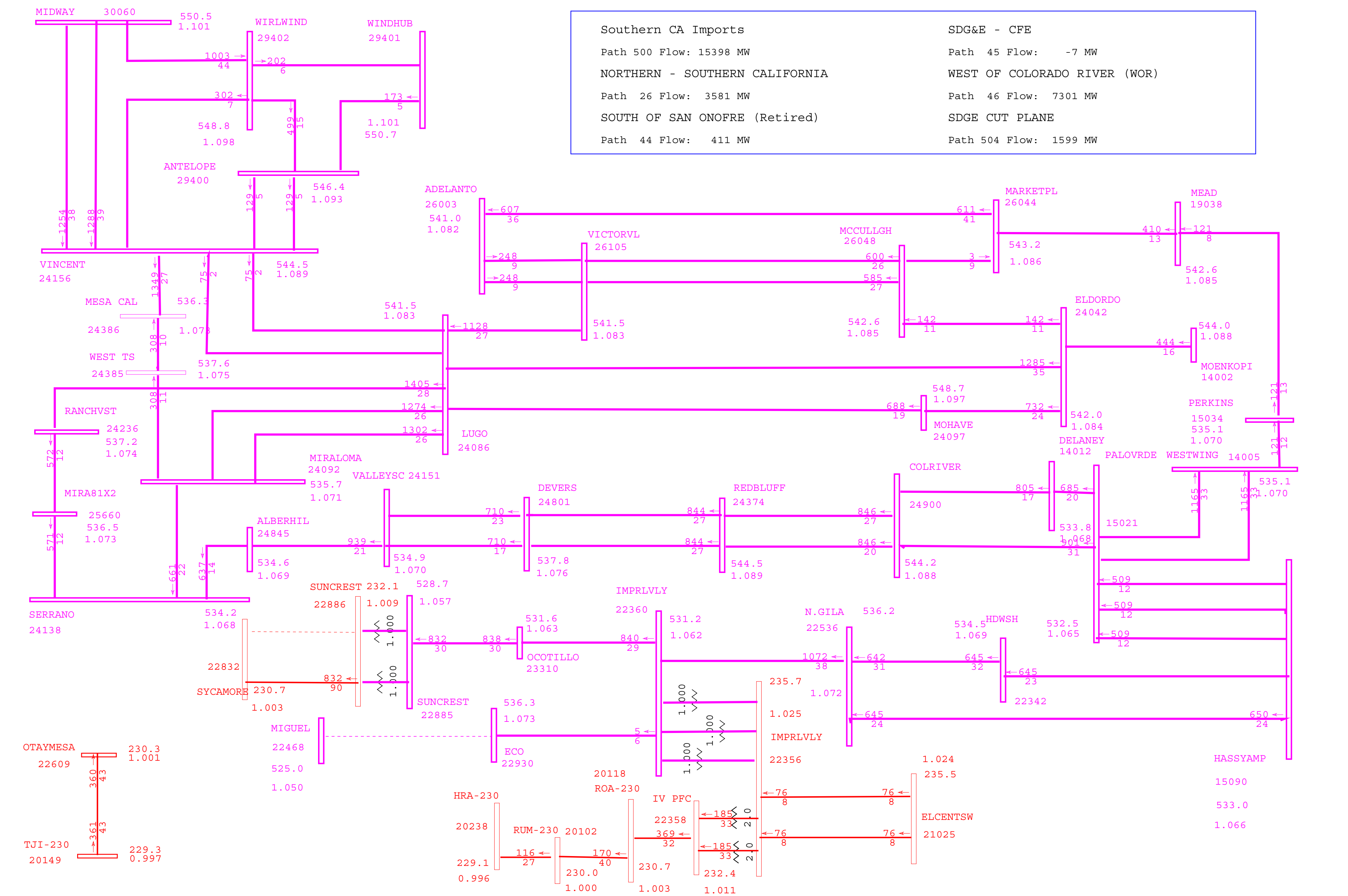
	WESTERN ELECTRICITY COORDINATING COUNCIL 2028 HS1 ADS PLANNING CASE, DECEMBER 20, 2017 TPP 2018-2019 SDGE-Main 2028SP Base Case	Figure 3Y-GE_Step2: After adjusting System and IV-PST for the 1st P1 event of ECO-Miguel 500KV line	MW/% rate SDGE_2019-V1.drw Rating = 2

Southern CA Imports	SDG&E - CFE
Path 500 Flow: 15407 MW	Path 45 Flow: 1 MW
NORTHERN - SOUTHERN CALIFORNIA	WEST OF COLORADO RIVER (WOR)
Path 26 Flow: 3591 MW	Path 46 Flow: 7301 MW
SOUTH OF SAN ONOFRE (Retired)	SDGE CUT PLANE
Path 44 Flow: 601 MW	Path 504 Flow: 1604 MW



General Electric International, Inc. PSLF Program Fri Sep 13 13:05:53 2019 3Y-GE_Step3_B3_SDGE-Main_2028SP_V1.sav

WESTERN ELECTRICITY COORDINATING COUNCIL 2028 HS1 ADS PLANNING CASE, DECEMBER 20, 2017 TPP 2018-2019 SDGE-Main 2028SP Base Case	Figure 3Y-GE3_Step3: After the RAS action but prior to adjusting IV-PST for the 2nd P1 event of either of SCR-SX lines	MW/% rate SDGE_2019-V1.drw Rating = 2



General Electric International, Inc. PSLF Program Fri Sep 13 13:06:42 2019 3Y-GE_Step4_B3_SDGE-Main_2028SP_V1.sav

WESTERN ELECTRICITY COORDINATING COUNCIL 2028 HS1 ADS PLANNING CASE, DECEMBER 20, 2017 TPP 2018-2019 SDGE-Main 2028SP Base Case	Figure 3Y-GE_Step4: After IV-PST adjustment (380 MW via IV-PST) for the 2nd P1 event of either of SCR-SX lines	MW/% rate SDGE_2019-V1.drw Rating = 2

Attachment C

Power Flow Plots

With Operational Mitigation Addressing the P6 SCR-SX Overload Concern

Based on the Revised TPP 2018-19 TPP SDGE-Main Base Cases

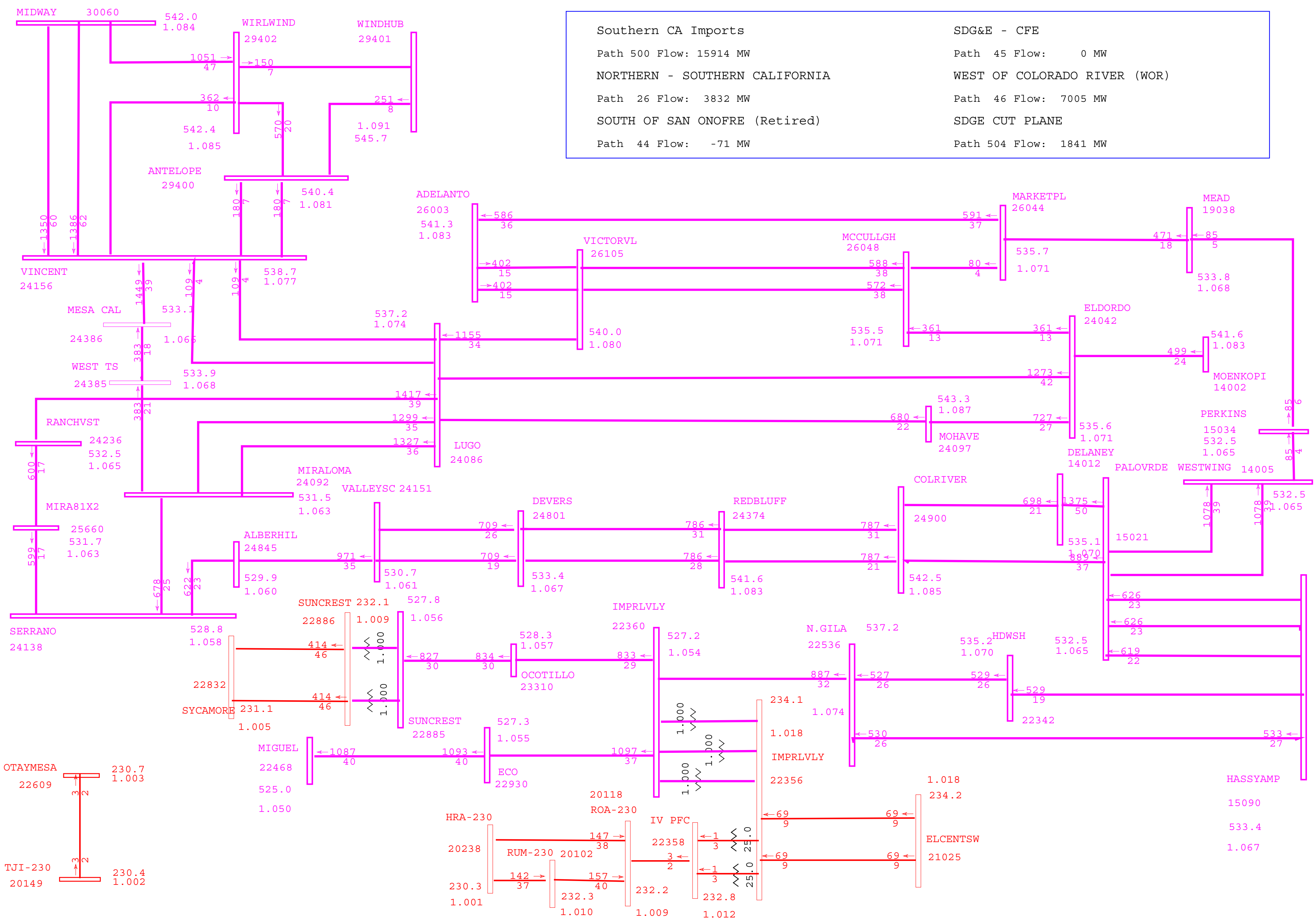
Revised 2023 Summer Peak Base Case

- Figure RE-2Y-GE_Step0
- Figure RE-2Y-GE_Step1
- Figure RE-2Y-GE_Step2
- Figure RE-2Y-GE_Step3
- Figure RE-2Y-GE_Step4

Revised 2028 Summer Peak Base Case

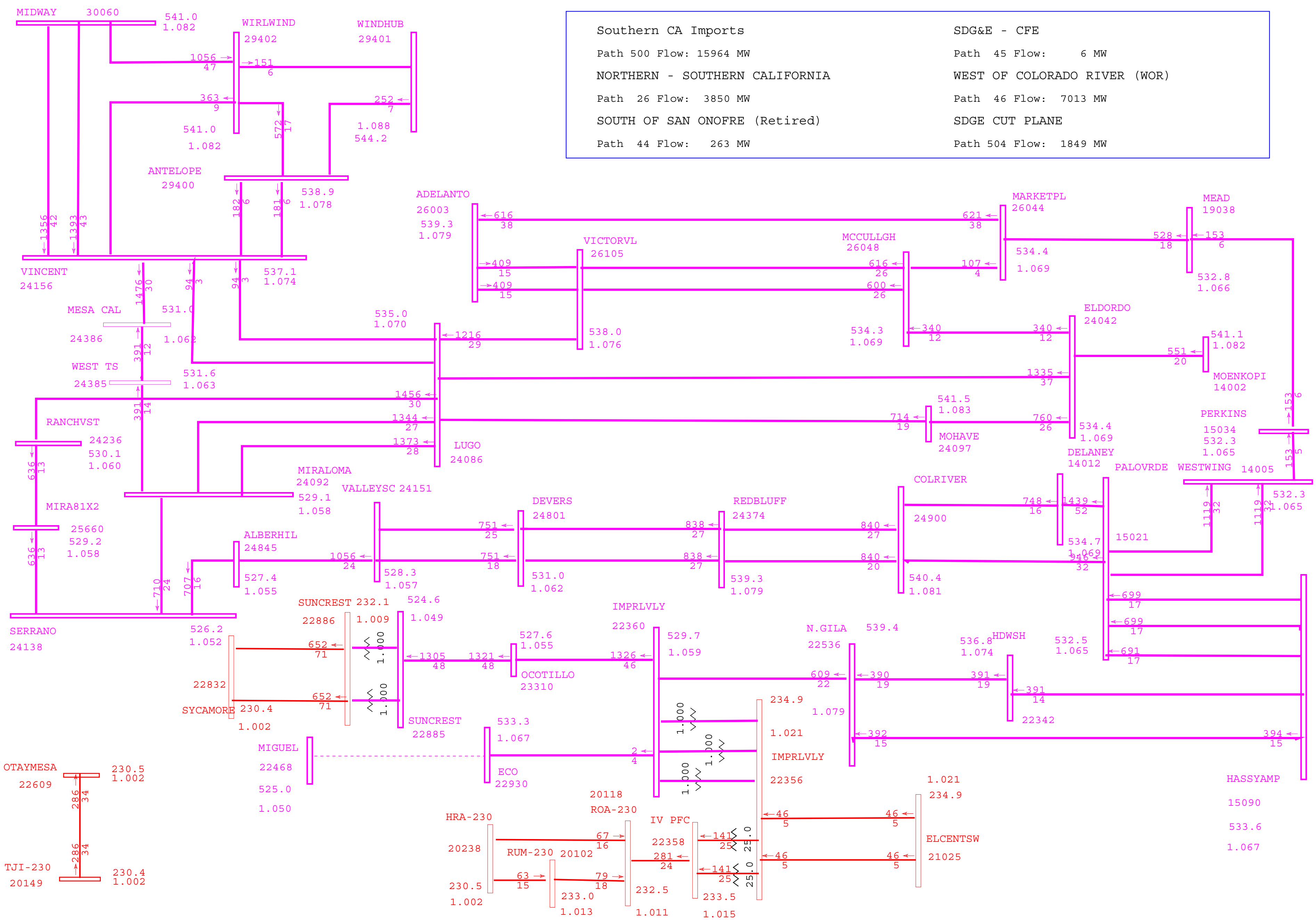
- Figure RE-3Y-GE_Step0
- Figure RE-3Y-GE_Step1
- Figure RE-3Y-GE_Step2
- Figure RE-3Y-GE_Step3
- Figure RE-3Y-GE_Step4

Southern CA Imports	SDG&E - CFE
Path 500 Flow: 15914 MW	Path 45 Flow: 0 MW
NORTHERN - SOUTHERN CALIFORNIA	WEST OF COLORADO RIVER (WOR)
Path 26 Flow: 3832 MW	Path 46 Flow: 7005 MW
SOUTH OF SAN ONOFRE (Retired)	SDGE CUT PLANE
Path 44 Flow: -71 MW	Path 504 Flow: 1841 MW



General Electric International, Inc. PSLF Program Fri Sep 13 13:22:28 2019 RE-B2_SDGE-Main_2023SP_V1.sav

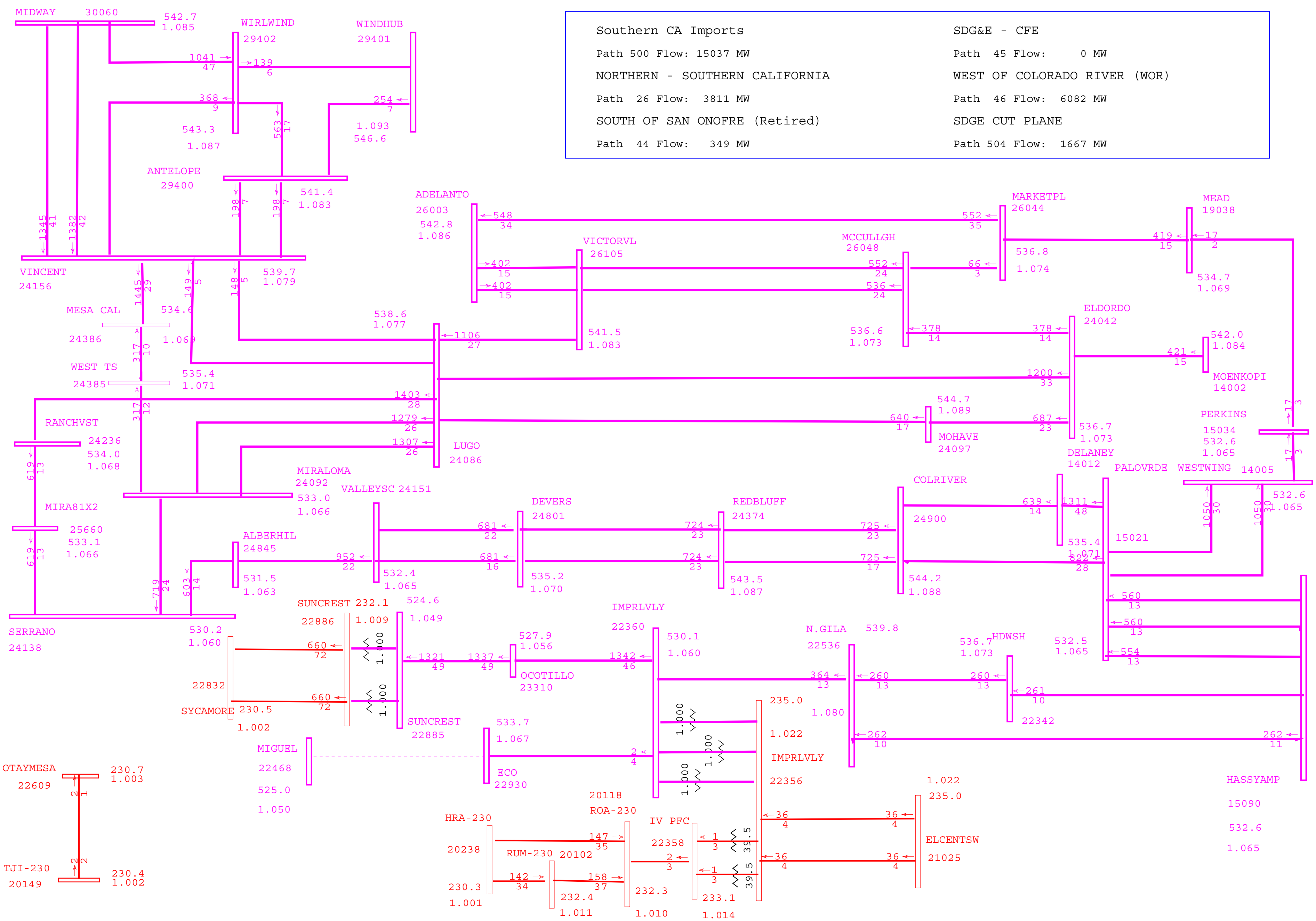
WESTERN ELECTRICITY COORDINATING COUNCIL 2023 HS2a, July 19, 2017 TPP 2018-2019 SDGE-Main 2023SP Base Case Revised	Figure RE-2Y-GE_Step0: Initial Operating Condition For P0 contingency (all Elements are in service)	MW/% rate SDGE_2019-V1.drw Rating = 1



General Electric International, Inc. PSLF Program Fri Sep 13 13:11:09 2019 RE-2Y-GE_Step1_B2_SDGE-Main_2023SP_V1.sav

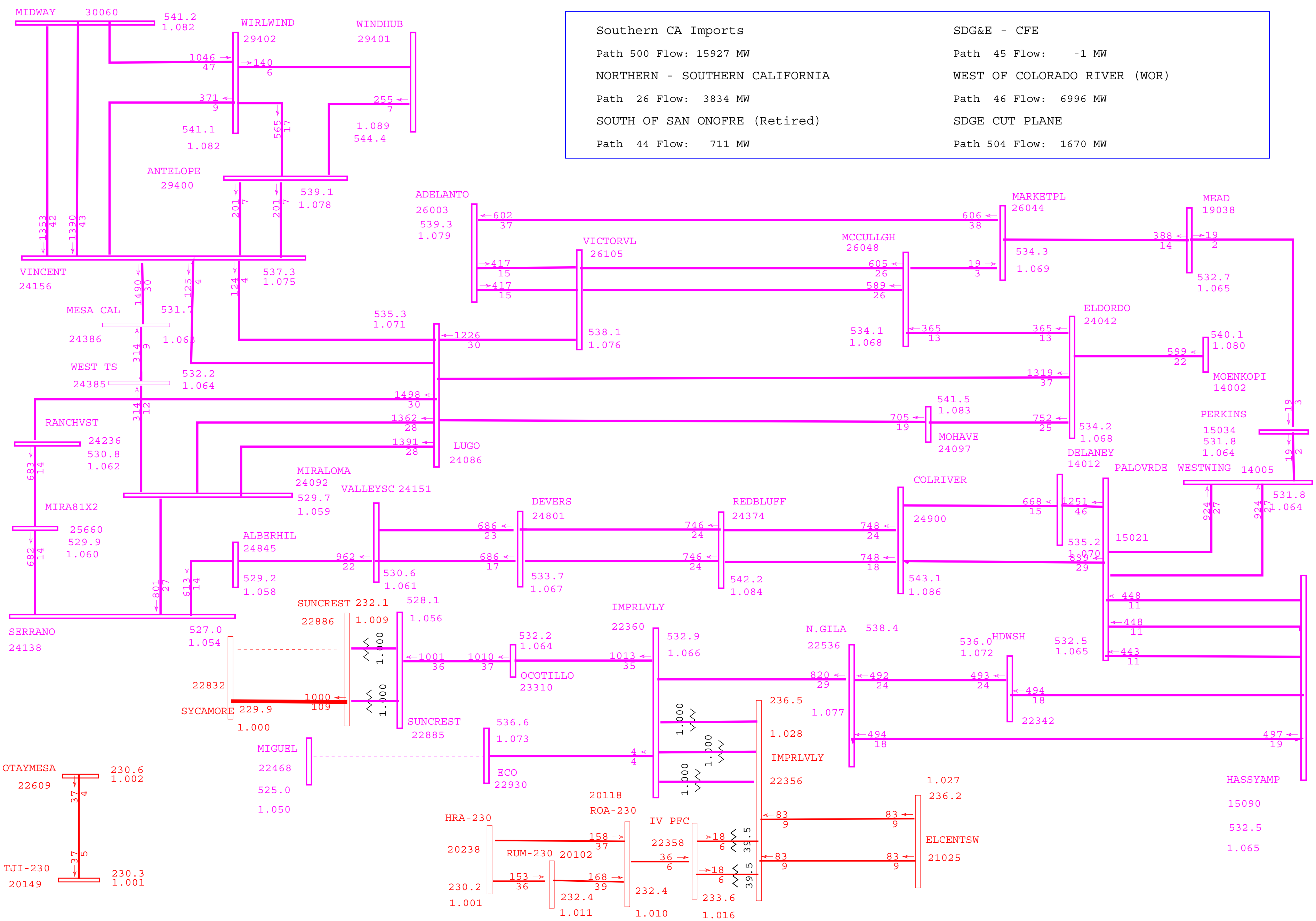
WESTERN ELECTRICITY COORDINATING COUNCIL 2023 HS2a, July 19, 2017 TPP 2018-2019 SDGE-Main 2023SP Base Case Revised	Figure RE-2Y-GE_Step1: Prior to adjusting IV-PST for the 1st P1 event of ECO-Miguel 500kV line	MW/% rate SDGE_2019-V1.drw Rating = 2

Southern CA Imports	SDG&E - CFE
Path 500 Flow: 15037 MW	Path 45 Flow: 0 MW
NORTHERN - SOUTHERN CALIFORNIA	WEST OF COLORADO RIVER (WOR)
Path 26 Flow: 3811 MW	Path 46 Flow: 6082 MW
SOUTH OF SAN ONOFRE (Retired)	SDGE CUT PLANE
Path 44 Flow: 349 MW	Path 504 Flow: 1667 MW



General Electric International, Inc. PSLF Program Fri Sep 13 13:11:36 2019 RE-2Y-GE_Step2_B2_SDGE-Main_2023SP_V1.sav

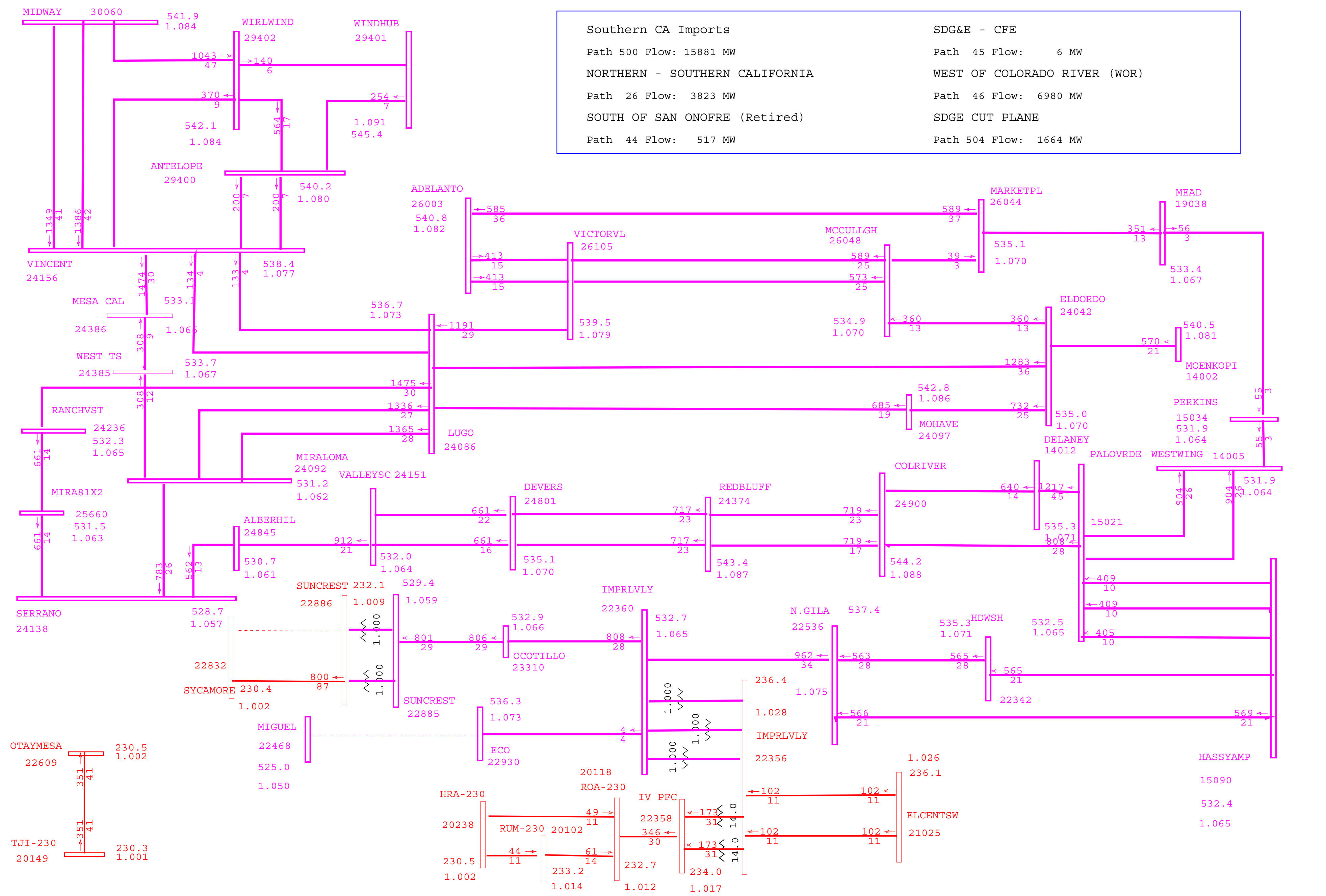
WESTERN ELECTRICITY COORDINATING COUNCIL 2023 HS2a, July 19, 2017 TPP 2018-2019 SDGE-Main 2023SP Base Case Revised	Figure RE-2Y-GE_Step2: After adjusting System and IV-PST for the 1st P1 event of ECO-Miguel 500KV line	MW/% rate SDGE_2019-V1.drw Rating = 2



Southern CA Imports	SDG&E - CFE
Path 500 Flow: 15927 MW	Path 45 Flow: -1 MW
NORTHERN - SOUTHERN CALIFORNIA	WEST OF COLORADO RIVER (WOR)
Path 26 Flow: 3834 MW	Path 46 Flow: 6996 MW
SOUTH OF SAN ONOFRE (Retired)	SDGE CUT PLANE
Path 44 Flow: 711 MW	Path 504 Flow: 1670 MW

General Electric International, Inc. PSLF Program Fri Sep 13 13:12:22 2019 RE-2Y-GE_Step3_B2_SDGE-Main_2023SP_V1.sav

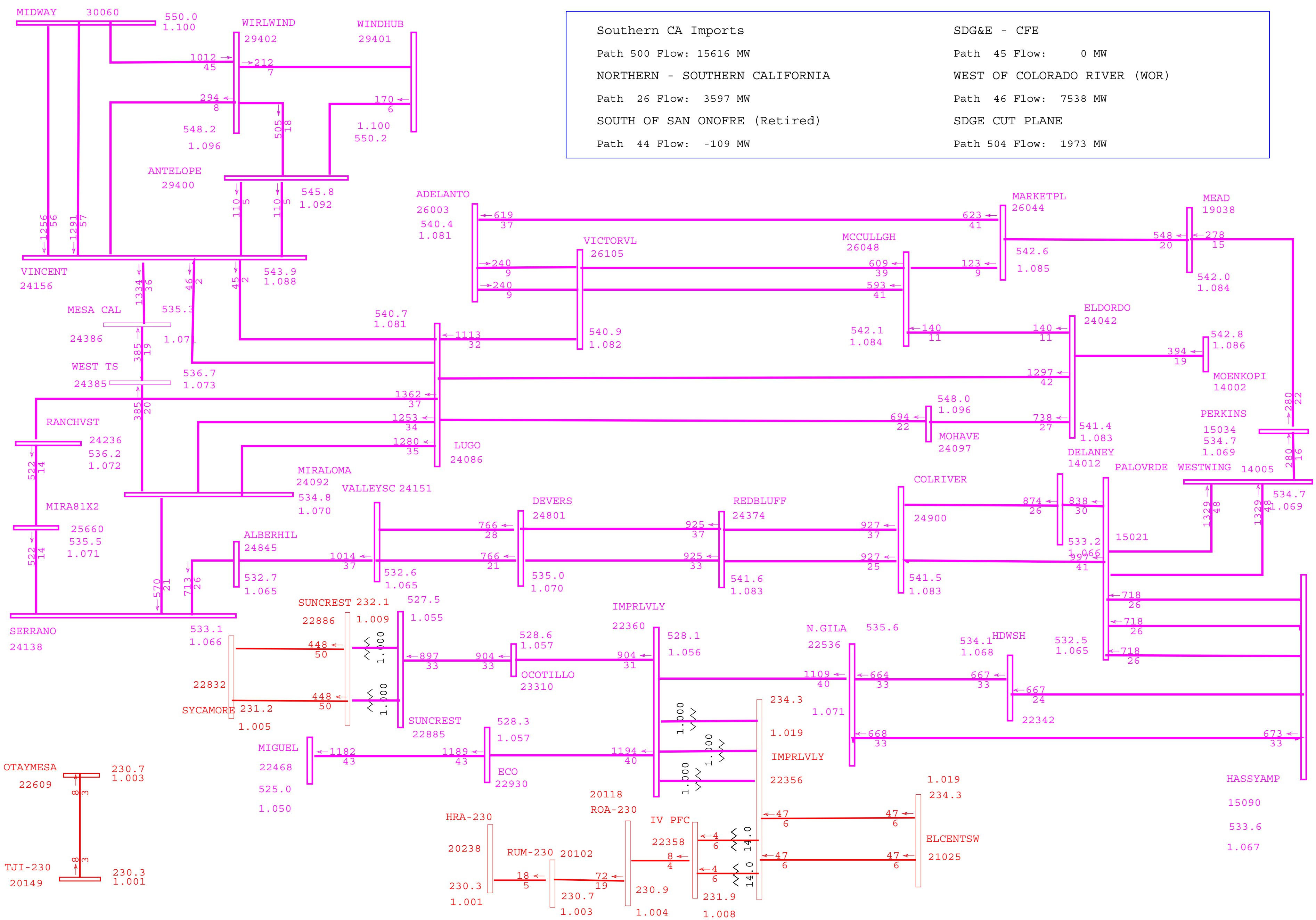
WESTERN ELECTRICITY COORDINATING COUNCIL 2023 HS2a, July 19, 2017 TPP 2018-2019 SDGE-Main 2023SP Base Case Revised	Figure RE-2Y-GE_Step3: After the RAS action but prior to adjusting IV-PST for the 2nd P1 event of either of SCR-SX lines	MW/% rate SDGE_2019-V1.drw Rating = 2



General Electric International, Inc. PSLF Program Fri Sep 13 13:13:20 2019 RE-2Y-GE_Step4_B2_SDGE-Main_2023SP_V1.sav

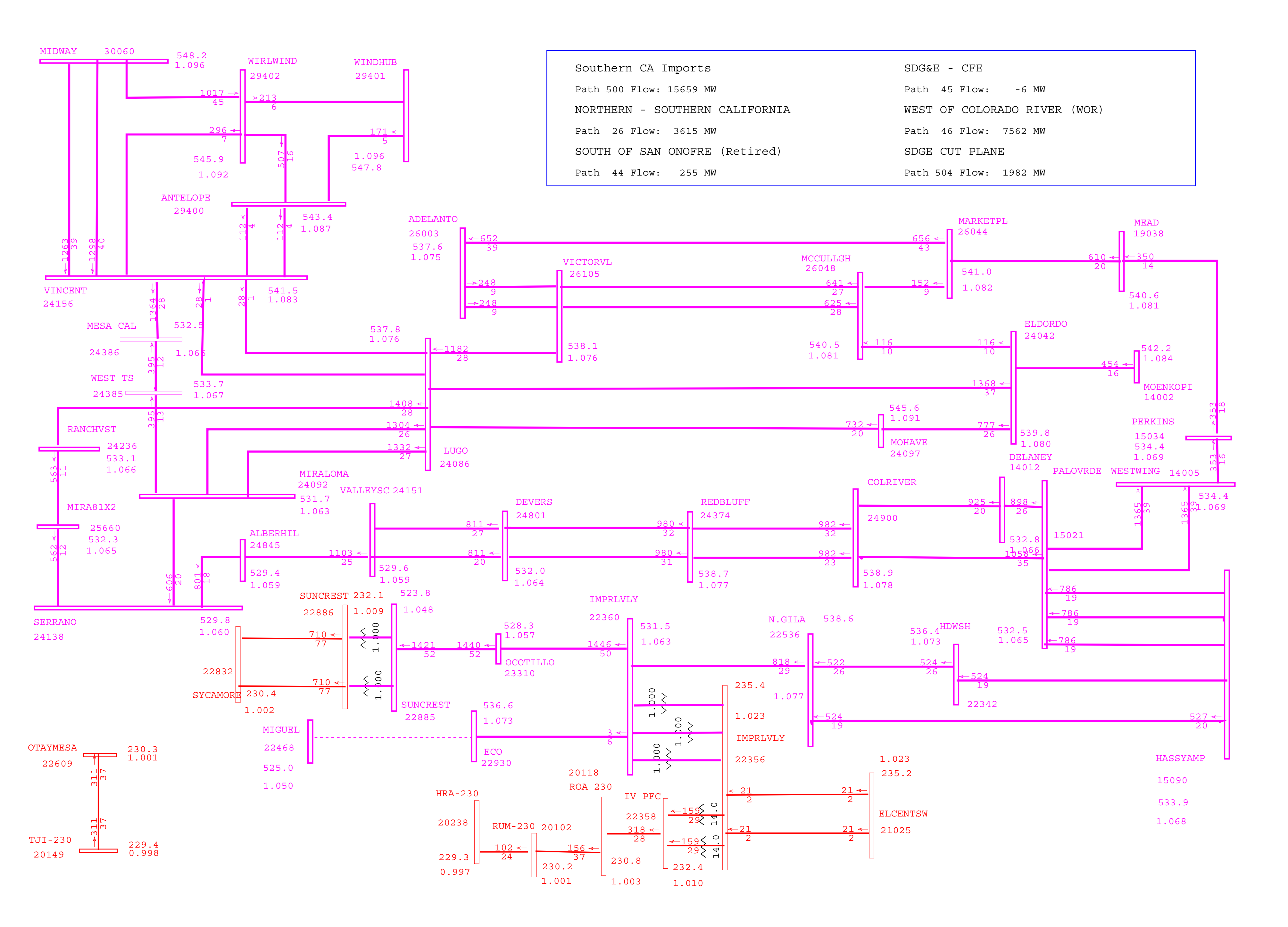
	WESTERN ELECTRICITY COORDINATING COUNCIL 2023 HS2a, July 19, 2017 TPP 2018-2019 SDGE-Main 2023SP Base Case Revised	Figure RE-2Y-GE_Step4: After adjusting IV-PST (350 MW via IV-PST) for the 2nd P1 event of either of SCR-SX lines	MW/% rate SDGE_2019-V1.drw Rating = 2

Southern CA Imports	SDG&E - CFE
Path 500 Flow: 15616 MW	Path 45 Flow: 0 MW
NORTHERN - SOUTHERN CALIFORNIA	WEST OF COLORADO RIVER (WOR)
Path 26 Flow: 3597 MW	Path 46 Flow: 7538 MW
SOUTH OF SAN ONOFRE (Retired)	SDGE CUT PLANE
Path 44 Flow: -109 MW	Path 504 Flow: 1973 MW



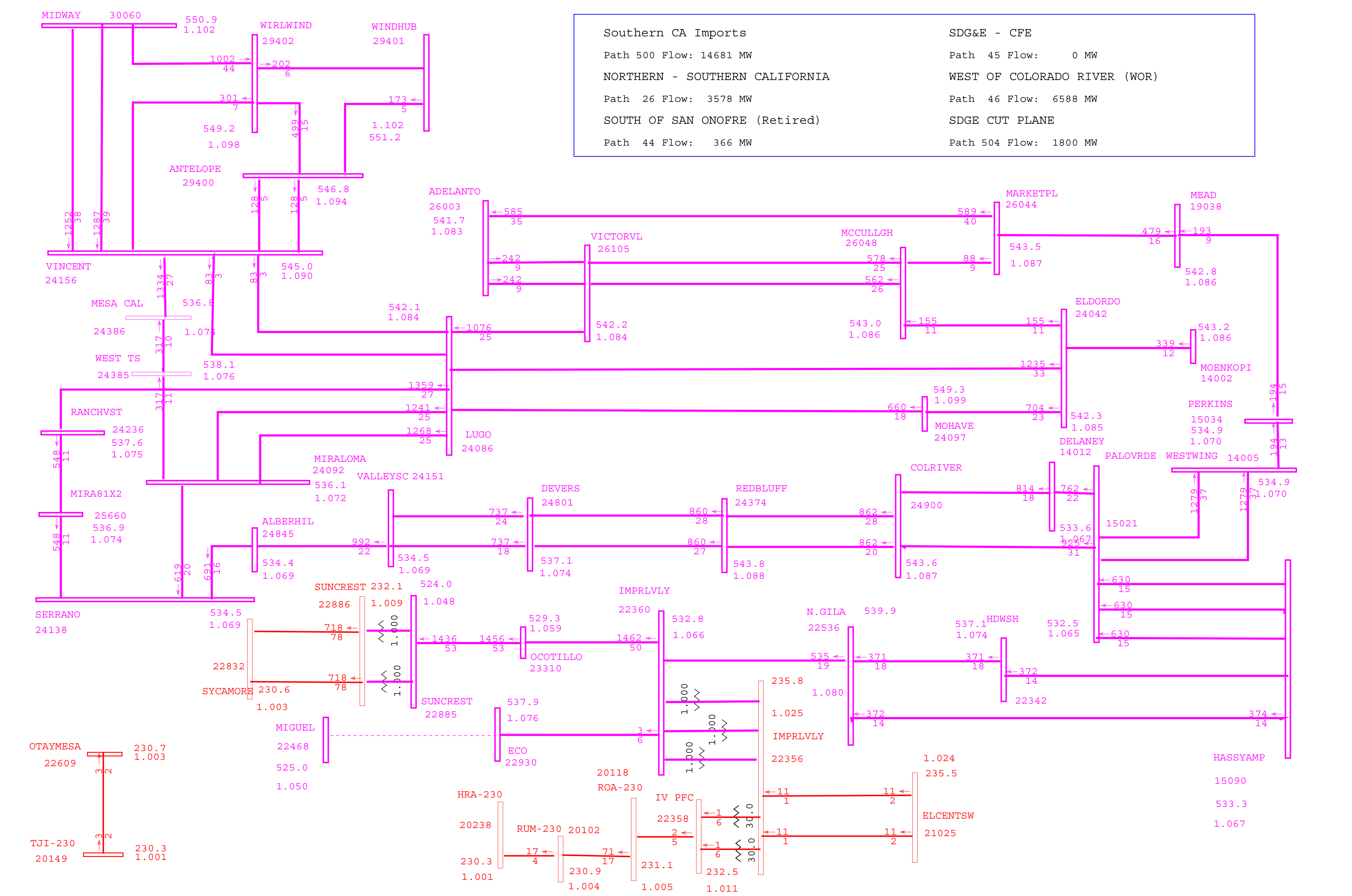
General Electric International, Inc. PSLF Program Fri Sep 13 13:22:57 2019 RE-B3_SDGE-Main_2028SP_V1.sav

WESTERN ELECTRICITY COORDINATING COUNCIL 2028 HS1 ADS PLANNING CASE, DECEMBER 20, 2017 TPP 2018-2019 SDGE-Main 2028SP Base Case - Revised	Figure RE-3Y-GE_Step0: Initial Operating Condition For P0 contingency (all Elements are in service)	MW/% rate SDGE_2019-V1.drw Rating = 1



General Electric International, Inc. PSLF Program Fri Sep 13 13:13:55 2019 RE-3Y-GE_Step1_B3_SDGE-Main_2028SP_V1.sav

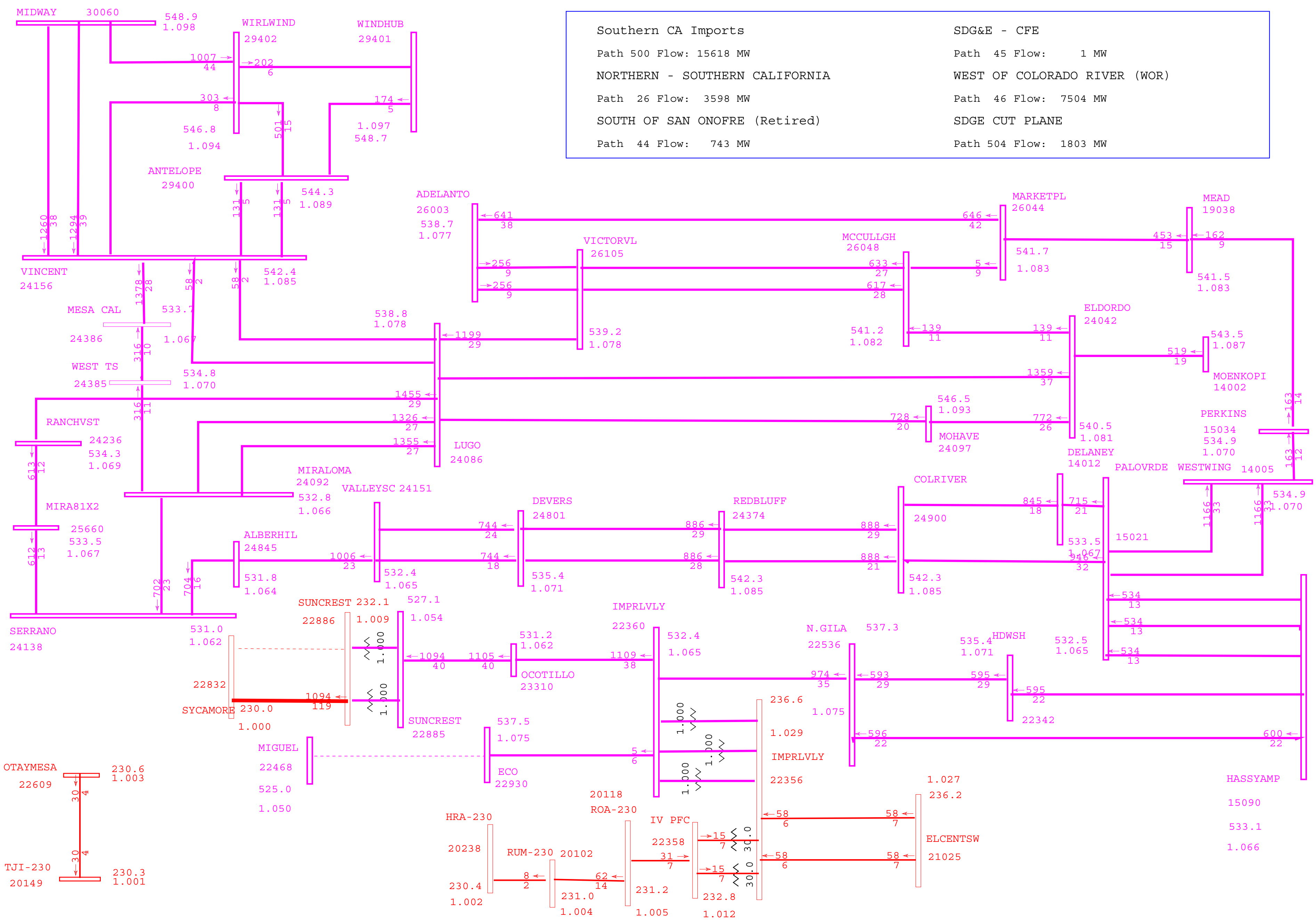
WESTERN ELECTRICITY COORDINATING COUNCIL 2028 HS1 ADS PLANNING CASE, DECEMBER 20, 2017 TPP 2018-2019 SDGE-Main 2028SP Base Case - Revised	Figure RE-3Y-GE_Step1: Prior to adjusting IV-PST for the 1st P1 event of ECO-Miguel 500kV line	MW/% rate SDGE_2019-V1.drw Rating = 2



General Electric International, Inc. PSLF Program Fri Sep 13 13:14:32 2019 RE-3Y-GE_Step2_B3_SDGE-Main_2028SP_V1.sav

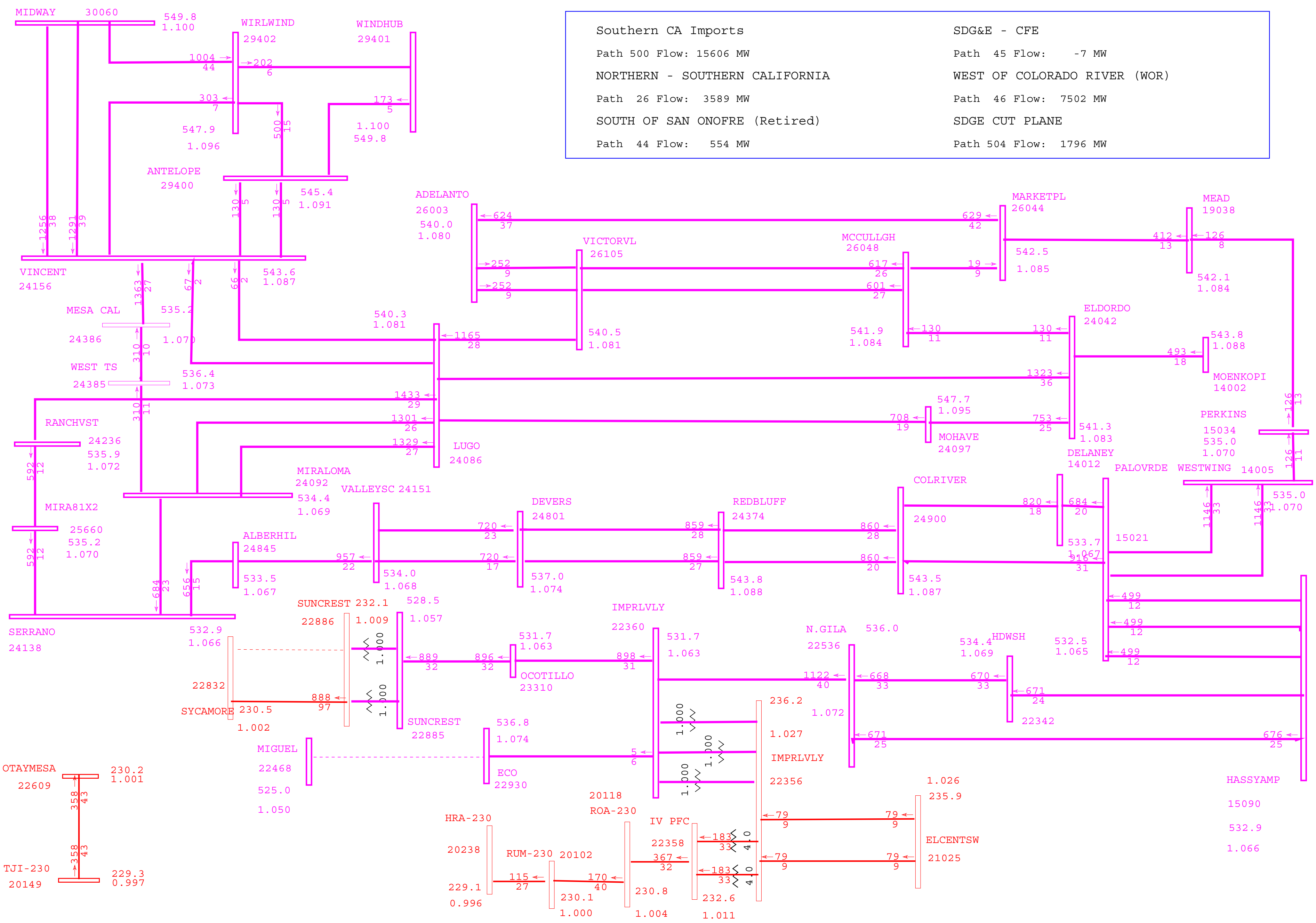
WESTERN ELECTRICITY COORDINATING COUNCIL 2028 HS1 ADS PLANNING CASE, DECEMBER 20, 2017 TPP 2018-2019 SDGE-Main 2028SP Base Case - Revised	Figure RE-3Y-GE_Step2: After adjusting System and IV-PST for the 1st P1 event of ECO-Miguel 500KV line	MW/% rate SDGE_2019-V1.drw Rating = 2

Southern CA Imports	SDG&E - CFE
Path 500 Flow: 15618 MW	Path 45 Flow: 1 MW
NORTHERN - SOUTHERN CALIFORNIA	WEST OF COLORADO RIVER (WOR)
Path 26 Flow: 3598 MW	Path 46 Flow: 7504 MW
SOUTH OF SAN ONOFRE (Retired)	SDGE CUT PLANE
Path 44 Flow: 743 MW	Path 504 Flow: 1803 MW



General Electric International, Inc. PSLF Program Fri Sep 13 13:15:51 2019 RE-3Y-GE_Step3_B3_SDGE-Main_2028SP_V1.sav

WESTERN ELECTRICITY COORDINATING COUNCIL 2028 HS1 ADS PLANNING CASE, DECEMBER 20, 2017 TPP 2018-2019 SDGE-Main 2028SP Base Case - Revised	Figure RE-3Y-GE_Step3: After the RAS action but prior to adjusting IV-PST for the 2nd P1 event of either of SCR-SX lines	MW/% rate SDGE_2019-V1.drw Rating = 2



General Electric International, Inc. PSLF Program Fri Sep 13 13:20:30 2019 RE-3Y-GE_Step4_B3_SDGE-Main_2028SP_V1.sav

WESTERN ELECTRICITY COORDINATING COUNCIL
2028 HS1 ADS PLANNING CASE, DECEMBER 20, 2017
TPP 2018-2019 SDGE-Main 2028SP Base Case - Revised

Figure RE-3Y-GE_Step4: After adjusting IV-PST (380 MW via IV-PST)
for the 2nd P1 event of either of SCR-SX lines

MW/% rate
SDGE_2019-V1.drw
Rating = 2

Attachment D

Tabulated Step by Step Results of Power Flow Plots
Addressing the P6 SCR-SX Overload Concern
Based on the TPP 2018-19 TPP SDGE-Main Base Cases

2023 Summer Peak Base Case
2028 Summer Peak Base Case

- Table 1: Step by step tabulation of the posted base case analysis results at each step of the contingency analysis, without and with mitigations. (Includes the TARA-generated simulation that aligns with 2018-2019 ISO Transmission Plan Appendix C tabulated results)
- Table 2: Step by step tabulation of the results from the posted base cases adjusted by retiring the Naval Station generation (93.8 MW qualifying capacity) at each step of the contingency analysis, with mitigations.

Table 1: Power flow results with and without operational mitigation eliminating the P6 SCR-SX 230 kV overload concern - Based on the TPP 2018~2019 assumptions

Monitored Element	Contingency Description		Detail action for each of the two overlapping P1 events		Thermal Loading Level on remaining SCR-SX 230 kV in % over its Continous Rating		Power Flow One-Line Plot
			Individual event	operational action in simulation	B2-23SP 2023 Summer Peak Case	B3-28SP 2028 Summer Peak Case	
Remaining SCR-SX 230 kV line	Initial operating condition		P0 no contingency with all Elements in service		45%	48%	Figure 2N-GE_Step0 Figure 3N-GE_Step0
	ECO-Miguel 500 kV line out of service (1st P1 event) followed by either of SCR-SX 230 kV lines (2nt P1 event) (the worst P6 Contingency)	Without the operational mitigation	1st P1 event	No major action	70%	75%	Figure 2N-GE_Step1 Figure 3N-GE_Step1
				Adjust IV-PST	78%	83%	Figure 2N-GE_Step2 Figure 3N-GE_Step2
			2nd P1 event (Simulation in GE-PSLF *)	1. TL23054/55 RAS taking action to drop generation in the greater IV area (915 MW output in total for the cases) 2. PSLF swing bus located in APS picked up the 915 MW generation in simulation	119%	128%	Figure 2N-GE_Step3 Figure 3N-GE_Step3
			2nd P1 event (Simulation in PowerGEN-TARA *)		121%	128%	Figure 2N-TARA_Step3 Figure 3N-TARA_Step3
		With the operational mitigation	1st P1 event	No major action	70%	75%	Figure 2Y-GE_Step1 Figure 3Y-GE_Step1
				1. Dispatch 998 MW and 1022 MW of PR in 23SP and 28SP cases respectively 2. bring down about 998 MW and 1022 MW of geneneration in the APS area accordingly 3. Automatically adjust IV-PST	70%	75%	Figure 2Y-GE_Step2 Figure 3Y-GE_Step2
			2nd P1 event	1. TL23054/55 RAS taking action to drop generation in the greater IV area (915 MW output in total for the cases) 2. PSLF swing bus located in APS picked up the 915 MW generation in simulation	105%	113%	Figure 2Y-GE_Step3 Figure 3Y-GE_Step3
				Adjusting IV-PST to re-route/optimize the power flow via CENACE in 30 minutes (350 MW in 23SP case and 380 MW in 28SP case)	83%	90%	Figure 2Y-GE_Step4 Figure 3Y-GE_Step4

Note: * GE-PSLF is used as it facilitates effort to demonstrate detailed operational procedures in the power flow simulation. In addition, PowerGEM-TARA was also used to reproduce the original results posted on August 15, 2018 and in appendix C of the 2018-2019 TPP report, and to show the minor differences in the simulations between PSLF and TARA.

Table 2: Power flow results with operational mitigation addressing the P6 SCR-SX 230 kV overload concern - Based on revised generation assumptions in SDGE

Monitored Element	Contingency Description	Detail action for each of the two overlapping P1 events		Thermal Loading Level on remaining SCR-SX 230 kV in % over its Continous Rating		Power Flow Plot ID
		Individual event	**operational action in simulation**	**B2-23SP 2023 Summer Peak Case**	**B3-28SP 2028 Summer Peak Case**	
Remaining SCR-SX 230 kV line	Revised Initial operating condition	P0 Initial operating condition with all Elements in service		46%	50%	Figure RE-2Y-GE_Step0 Figure RE-3Y-GE_Step0
	ECO-Miguel 500 kV line out of service (1st P1 event) followed by either of SCR-SX 230 kV lines (2nt P1 event) (the worst P6 Contingency)	1st P1 event	No major action	71%	77%	Figure RE-2Y-GE_Step1 Figure RE-3Y-GE_Step1
			1. Dispatch 998 MW and 1022 MW of PR in 23SP and 28SP cases respectively 2. bring down about 998 MW and 1022 MW of geneneration in the APS area accordingly 3. Adjust IV-PST	72%	78%	Figure RE-2Y-GE_Step2 Figure RE-3Y-GE_Step2
		2nd P1 event	1. TL23054/55 RAS taking action to drop generation in the greater IV area (915 MW output in total for the cases) 2. PSLF swing bus located in APS picked up the 915 MW generation in simulation	109%	119%	Figure RE-2Y-GE_Step3 Figure RE-3Y-GE_Step3
			Adjusting IV-PST to re-route/optimize the power flow via CENACE in 30 minutes (350 MW in 23SP case and 380 MW in 28SP case)	87%	97%	Figure RE-2Y-GE_Step4 Figure RE-3Y-GE_Step4

Notes:

* The SDGE-Main 2023SP base case was revised to reflect a total of 93.8 MW generation that were retired in the SDGE area after the Table 1 studies were completed (Naval Station)

** The SDGE-Main 2028SP base case was revised to reflect the 93.8 MW generation retirement (Naval Station) and to remove 100 MW of generation in the base case that was inadvertently dispatched in the original results on Table 1, (Q189GEN2 at bus 22789).