2013-2014 TRANSMISSION PLAN

California ISO
Shaping a Renewed Future

March 25, 2014

Prepared by: Infrastructure Development
Approved by: ISO Board of Governors

Forward to the Board-Approved 2013-2014 Transmission Plan

At the March 20, 2014 ISO Board of Governors meeting, the ISO Board of Governors approved the 2013-2014 Transmission Plan with the exception of the Delaney-Colorado River 500 kV line, which was recommended for approval as an economically driven project. The ISO will conduct further assessment of the Delaney-Colorado River 500 kV line project and will report back to the Board after the additional assessment has been conducted. Changes to the final 2013-2014 Transmission Plan from the plan submitted to the Board for approval, have been noted with footnotes.

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Executive Summary

Introduction

The 2013-2014 California Independent System Operator Corporation Transmission Plan provides a comprehensive evaluation of the ISO transmission grid to identify upgrades needed to successfully meet California's policy goals, in addition to examining conventional grid reliability requirements and projects that can bring economic benefits to consumers. This plan is updated annually, and is prepared in the larger context of supporting important energy and environmental policies while maintaining reliability through a resilient electric system.

In recent years, California enacted policies aimed at reducing greenhouse gases and increasing renewable resource development. The state's goal, to have renewable resources provide 33 percent of California's retail electricity consumption by 2020, has become the principal driver of substantial investment in new renewable generation capacity both inside and outside of California.

As well, the early retirement of the San Onofre Nuclear Generating Station coupled with the impacts of potential retirement of gas-fired generation in the San Diego and LA Basin areas – largely to eliminate coastal water use in "once-through cooling" have created both opportunities for development of preferred resources as well as challenges in ensuring continued reliable service in these areas.

The transmission plan describes the transmission necessary to meet the state's needs. Key analytic components of the plan include the following:

- continuing to refine the plans for transmission needed to support meeting the 33 percent RPS goals over a diverse range of renewable generation portfolio scenarios, which are based on plausible forecasts of the type and location of renewable resources in energy-rich areas most likely to be developed over the 10 year planning horizon;
- developing the necessary information to support advancement of preferred resources in meeting southern California needs, taking immediate steps regarding "least regrets" transmission that can contribute to the overall solution, and providing a framework for future consideration of additional transmission development;
- identifying transmission upgrades and additions needed to reliably operate the network and comply with applicable planning standards and reliability requirements; and
- performing economic analysis that considers whether transmission upgrades or additions could provide additional ratepayer benefits.

In addition, the identification of the roles non-transmission alternatives, particularly preferred resources and storage, can play where more than solely transmission reinforcement is required has also become a key focus of the transmission planning analysis that underpins the transmission planning efforts. In this regard, the ISO's transmission planning efforts focus on not only meeting the state's policy objectives in advancing policy-driven transmission, but also to help transform the electric grid in an environmentally responsible way. The focus on a cleaner lower emission future governs not only policy-driven transmission, but our path on meeting other electric system needs as well.

Our comprehensive evaluation of the areas listed above resulted in the following key findings:

- the ISO identified 28 transmission projects with an estimated cost of approximately $1.70 billion as needed to maintain transmission system reliability. Three of these mitigations were identified specifically to address reliability needs in the LA Basin and San Diego areas in light of the retirement of the SONGS generation coupled with the impacts of potential retirement of gas-fired generation in the San Diego and LA Basin areas;
- one service area, the San Francisco peninsula, has been identified by PG&E as being particularly vulnerable to lengthy outages in the event of extreme (NERC Category D) contingencies, and further research was undertaken in this planning cycle to determine the need and options for reinforcement. However, the ISO has determined that more analysis of the reliability risks and the benefits that potential reinforcement options would have in reducing those risks is needed. The ISO plans to undertake this analysis this year and may bring forward a recommendation for ISO Board approval as an addendum to this plan or in the next planning cycle as part of the 2014-15 Transmission Plan;
- consistent with recent transmission plans, no new major transmission projects have been identified at this time to support achievement of California's 33 percent renewables portfolio standard given the transmission projects already approved or progressing through the California Public Utilities Commission approval process. However;
    - 2 smaller policy-driven transmission upgrades have been identified in this transmission plan, which the ISO is recommending for approval in this plan;
    - the deliverability of future renewable generation from the Imperial Valley area may be significantly reduced primarily due to changes in flow patterns resulting from the retirement of the San Onofre Nuclear Generating Station. Despite the impacts being heavily offset by other reinforcements proposed in this transmission plan, only 1000 MW of the 1715 MW of Imperial zone renewable generation portfolio amounts can be made deliverable without additional actions. Given this significant change in circumstance, the ISO will conduct further study in the 2014-2015 transmission planning cycle to develop the most effective solution to achieve previously established target import capability levels.
- one economically driven 500 kV transmission project, the Delaney-Colorado River transmission project, is being recommended for approval;[1]
- one other economically driven project, a 500 kV transmission line from Eldorado to Harry Allen was found to provide significant potential benefits. However, due to recent announcements regarding the intention of NV Energy to join the ISO's energy imbalance market, the impact of this change on the benefits of the transmission project will need to

[1] The Delaney-Colorado River 500kV line was not approved by the ISO Board of Governors at the March 20, 2014 Board meeting.

be assessed before the ISO can make a recommendation on this project. The ISO intends to complete this review and bring the project forward for consideration at a future Board of Governors meeting; and

- the ISO tariff sets out a competitive solicitation process for reliability-driven, policy-driven and economically driven regional transmission facilities found to be needed in the plan.

  We have identified seven[2] solutions containing facilities that are eligible for competitive solicitation in this transmission plan:

  - Imperial Valley flow controller (if the back-to-back HVDC convertor is selected as the preferred technology)
  - Estrella 230/70 kV substation
  - Wheeler Ridge Junction 230/115 kV substation
  - Suncrest 300 Mvar Dynamic Reactive Support
  - Delaney-Colorado River project.[3]
  - Spring 230/115 kV substation near Morgan Hill
  - Miguel 500 kV Voltage Support

  Also, the other areas identified for further study could also trigger additional needs that, if approved by the Board, could be eligible for competitive solicitation.

This year's transmission plan is based on the ISO's transmission planning process, which involved collaborating with the California Public Utilities Commission and many other interested stakeholders. Summaries of the transmission planning process and some of the key collaborative activities are provided below. This is followed by additional details on each of the key study areas and associated findings described above.

The Transmission Planning Process

A core responsibility of the ISO is to plan and approve additions and upgrades to transmission infrastructure so that as conditions and requirements evolve over time, it can continue to provide a highly reliable and efficient bulk power system and well-functioning wholesale power market. Since it began operation in 1998, the ISO has fulfilled this responsibility through its annual transmission planning process. The State of California's adoption of new environmental policies and goals created a need for some important changes to the planning process. The ISO amended its tariff to address those needed changes, and the Federal Energy Regulatory Commission (FERC) approved the ISO tariff amendments on December 16, 2010. The amendments went into effect on December 20, 2010.

Those early changes provided a strong foundation for addressing the refinements driven in the regional components of FERC's Order 1000. On October 11, 2012, the ISO filed revisions to its

[2] There are only six solutions containing facilities that are eligible for competitive solicitation as the Delaney-Colorado River 500 kV line was not approved by the ISO Board of Governors at the March 20, 2014 ISO Board meeting.

[3] The Delaney-Colorado River 500 kV line was not approved by the ISO Board of Governors at the March 20, 2014 ISO Board meeting.

tariff to comply with the local and regional transmission and cost-allocation requirements of Order 1000. On April 18, 2013 FERC issued an order accepting the ISO's compliance filing, effective as of October 1, 2013, subject to a further compliance filing to clarify tariff provisions. The ISO made a supplemental compliance filing on August 20, 2013 that addressed such topics identified in the April 18 Order relating primarily to clarifications in the competitive solicitation process.

The ISO has also been implementing the integration of the transmission planning process with the generation interconnection procedures, based on the Generator Interconnection and Deliverability Allocation Procedures (GIDAP) approved by FERC in July 2012. The principal objectives of the GIDAP were to 1) ensure that, in the future, all major transmission additions and upgrades to be paid for by transmission ratepayers would be identified and approved under a single comprehensive process — the transmission planning process — rather than some projects coming through the transmission planning process and others through the generator interconnection process; 2) limit ratepayers' exposure to potentially costly interconnection-driven network upgrades that may not be most cost effective; and 3) enable the interconnection study process to determine meaningful network upgrade needs and associated cost estimates in a context where the volume of the interconnection queue vastly exceeds the amount of new generation that will actually be needed and built.

Collaborative Planning Efforts

The ISO, utilities, state agencies and other stakeholders continue to work closely to assess how to meet the environmental mandates established by state policy. The collaboration with these entities is evident in the following initiatives.

State Agency Coordination in Planning

State agency coordination in planning has taken significant steps forward in 2013 building further improvements that have impacted this year's plan as well as setting a stage for enhancements in future transmission planning cycles.

Preliminary Reliability Plan for LA Basin and San Diego:

In response to the announced closure of the San Onofre Nuclear Generating Station on June 7, 2013, the staff of the California Public Utilities Commission, the California Energy Commission and ISO developed a Preliminary Reliability Plan for the LA Basin and San Diego area. The draft, released on August 30, 2013, was developed in consultation with SWRCB, SCE, SDG&E and South Coast Air Quality Management District (SCAQMD) and describes the coordinated actions the CPUC, CEC, and CAISO staff are pursuing in the near term (4 years) and the long-term (7 years). These actions collectively comprised a preliminary reliability plan to address the closure of San Onofre, the expected closure of 5,068 MW of gas-fired generation that uses once-through cooling technology, and the normal patterns of load-growth. The preliminary plan highlights the importance of beginning planning now to make sure regulatory actions are made in time to meet future electricity needs in the region.

The reliability plan also identified challenging goals that will need to be fully vetted in the public decision making processes of the appropriate agency, with a focus on ensuring reliability, finding the most environmentally clean grid solutions, and urgently pursuing the variety of decisions that must ultimately be made and approved by key state agencies. The preliminary reliability plan contains the recommendations of CPUC, CEC and ISO. However, implementing the specific mitigation options discussed below will require decisions to be determined through CPUC or CEC proceedings, through the ISO planning process or both.

Process and Planning Assumptions Alignment – and Single Set of Forecast Assumptions

The ISO has worked collaboratively with the CPUC and the California Energy Commission (CEC) in 2013 to align the processes of future CPUC Long Term Procurement Planning processes, ISO transmission planning processes, and CEC Integrated Energy Policy Report proceedings.

Also, these agencies worked together to develop a "single managed forecast" to be used for the future local and system studies performed for both the transmission planning process and the LTPP process.

In addition to the single forecast set, the CPUC, CEC and ISO worked together to develop common planning assumptions and scenarios for the transmission planning process and the LTPP process. The assumptions utilize the single managed forecast as the basis for the demand side assumptions with common supply side assumptions developed taking into consideration the weather normalization for the different studies (local area, bulk, renewable portfolio and economic studies) and locational uncertainty for the Additional Achievable Energy Efficiency within the local area studies. Similarly, for the supply side, the assumptions are consistent and take into consideration the locational uncertainty of potential resources (i.e. demand response and storage) within the local area studies.

Based on the process alignment achieved to date and the progress on common planning assumptions, the ISO anticipates conducting future transmission planning process studies, 10-year Local Capacity Requirement studies, and system resource studies (including operational flexibility) during each transmission planning cycle, using the consistent planning assumptions established for both processes.

Inter-regional Planning Requirements of FERC Order 1000

In July 2011, FERC issued Order No. 1000 on "Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities." The order required the ISO to make a filing demonstrating that the ISO is a qualified regional planning entity under the definition of the order, and modifying the ISO tariff as needed to meet the regional planning provisions of the order as noted earlier. It also required the ISO to develop and file common tariff provisions with each of its neighboring planning regions to define a process whereby each pair of adjacent regions can identify and jointly evaluate potential inter-regional transmission projects that meet their transmission needs more cost-effectively or efficiently than projects in their regional plans, and to specify how the costs of such a project would be assigned to the relevant regions that have selected the inter-regional project in their regional transmission plans.

The four planning regions reached agreement on a "Proposed Interregional Coordination Approach," which was firmly grounded in Order 1000 principles and provided the framework for development of the tariff language that was ultimately proposed for inclusion placed in each transmission utility provider's tariff. On May 10, 2013 the ISO, along with transmission utility providers belonging to the NTTG, and WestConnect planning regions jointly submitted their Order 1000 interregional compliance filings. The ColumbiaGrid transmission utility providers submitted the joint tariff language in June 2013 as part of the ColumbiaGrid interregional. The ISO considers these filings to be a significant achievement by all four planning regions and a reflection of their commitment to work towards a successful and robust interregional planning process under Order 1000. FERC orders on these initial filings have not been received and the provisions are therefore not yet in effect. The ISO and its neighbors are nonetheless undertaking coordination activities to the extent possible.

Reliability Assessment

The reliability studies necessary to ensure compliance with North American Electric Reliability Corporation (NERC) and ISO planning standards are a foundational element of the transmission plan. During the 2012-2013 cycle, ISO staff performed a comprehensive assessment of the ISO controlled grid to ensure compliance with applicable NERC reliability standards. The analysis was performed across a 10-year planning horizon and modeled summer on-peak and off-peak system conditions. The ISO assessed transmission facilities across a voltage bandwidth of 60 kV to 500 kV, and where reliability concerns were identified, the ISO identified mitigation plans to address these concerns. These mitigation plans include upgrades to the transmission infrastructure, implementation of new operating procedures and installation of automatic special protection schemes. All ISO analysis, results and mitigation plans are documented in the transmission plan.

In total, this plan proposes approving 28 reliability-driven transmission projects, representing an investment of approximately $1.70 billion in infrastructure additions to the ISO controlled grid. The majority of these projects (22) cost less than $50 million and has a combined cost of $409 million. The remaining six projects with costs greater than $50 million have a combined cost of $1.29 billion and consist of the following:

- ***Mesa Loop-in* –** Looping the Vincent-Mira Loma 500 kV transmission line into the existing Mesa Substation, and upgrading the substation to include a 500 kV bus.
- ***Install Dynamic Reactive Support at San Luis Rey 230 kV Substation* –** Adding synchronous condensers at the San Luis Rey Substation to provide voltage support to the transmission system in the San Onofre area.
- ***Imperial Valley Flow Controller* –** Installing a phase shifter or back-to-back HVDC flow control device on path to CFE.
- ***Artesian 230 kV substation and loop-in* –** Upgrading the existing Artesian substation to 230 kV to provide a new source into the 69 kV system.
- ***Midway-Kern PP #2 230 kV line* –** Reconductoring and unbundling the existing Midway-Kern PP 230 kV line into two circuits and looping one of the new circuits into the Bakersfield substation.

- ***Wheeler Ridge Junction Station –*** Building a new 230/115 kV substation at Wheeler Ridge Junction and converting the existing Wheeler Ridge-Lamont 115 kV to 230kV operation.

These reliability projects are necessary to ensure compliance with the NERC and ISO planning standards. A summary of the number of projects and associated total costs in each of the four major transmission owners' service territories is listed below in Table 1. Because Pacific Gas and Electric (PG&E) and San Diego Gas and Electric (SDG&E) have lower voltage transmission facilities (138 kV and below) under ISO operational control, a higher number of projects were identified mitigating reliability concerns in those utilities' areas, compared to the lower number for Southern California Edison (SCE).

Table 1 – Summary of Needed Reliability-Driven Transmission Projects in the ISO 2013-2014 Transmission Plan

Service Territory	Number of Projects	Cost (in millions)
Pacific Gas & Electric (PG&E)	14	$486.4
Southern California Edison Co. (SCE)	2	$626.0
San Diego Gas & Electric Co. (SDG&E)	11	$584.0
Valley Electric Association (VEA)	1	0.1
Total	28	$1,696.5

The majority of identified reliability concerns are related to facility overloads or low voltage. Therefore, many of the specific projects that comprise the totals in Table 1 include line reconductoring and facility upgrades for relieving overloading concerns, as well as installing voltage support devices for mitigating voltage concerns. Additionally, some projects involve building new load-serving substations to relieve identified loading concerns on existing transmission facilities. Several initially identified reliability concerns were mitigated with non-transmission solutions. These include generation redispatch and, for low probability contingencies, possible load curtailment.

One service area, the San Francisco peninsula, has been identified by PG&E as being particularly vulnerable to lengthy outages in the event of extreme (NERC Category D) contingencies, and further research was undertaken in this planning cycle to determine the need and options for reinforcement. However, the ISO has determined that further analysis of the reliability risks and the benefits that potential reinforcement options would have in reducing those risks is needed. The ISO plans to undertake this analysis this year and may bring forward a recommendation for ISO Board approval as an addendum to this plan or in the next planning cycle as part of the 2014-2015 Transmission Plan.

Southern California Reliability Assessment (LA Basin and San Diego)

A major reliability focus of 2013-2014 transmission planning efforts has been the reliability needs in southern California – the LA Basin and San Diego area in particular – in light of the retirement of the SONGS generation coupled with the impacts of potential retirement of gas-fired generation in the San Diego and LA Basin areas.

As noted earlier, the ISO and state agency staff worked collaboratively to develop a preliminary draft plan, which helped frame the scope of the issues to be addressed and ensure coordinated action is being initiated in a number of fronts.

In this transmission plan, the ISO has accounted for the need for continued coordination and iterative dialogue with other state agency processes – the CPUC LTPP processes and CEC forecasting processes in particular, as well as the need to move decisively on “least regrets” transmission solutions that can play a significant role in addressing the local area challenges in the LA Basin and San Diego.

Additionally, the ISO has provided analysis of a number of preferred resource scenarios as well as a broad range of potential transmission solutions - using reduction in conventional generation needs as a measure of the potential benefits of these options. The analysis of preferred resource alternatives and storage alternatives will provide insight into utility procurement decisions.

The potential transmission solutions have been organized into three categories: 1) those optimizing existing transmission lines to address local area needs, 2) major new transmission that further reinforce the area and address reliability needs, and 3) major new transmission that would increase the import capability to the area and could potentially be coupled with other potential state policy objectives – such as promoting renewable energy development in certain areas of the state.

The ISO is recommending the first category of transmission solutions at this time, recognizing that there remains ample residual need for preferred resources and potentially other solutions, and margin for any reduction in local needs from future potential changes in load forecasts.

Advancing Preferred Resources

In 2013, the ISO made material strides in facilitating use of preferred resources to meet local transmission system needs. Much of these efforts were foundational – future plans will build on these first steps.

The ISO developed a methodology for examining the operational characteristics that non-conventional resources (e.g., demand response, storage) would need to play an increased role in addressing local transmission system needs.

Within this planning cycle, much of the effort focused on coordinating this analysis of local area requirements with the utilities, and testing the specific preferred scenarios being developed by the utilities for the LA Basin and San Diego needs as discussed above, which required adapting the general methodology instead to meeting the specific study requirements in these areas where more comprehensive solutions were required.

This initiative also resulted in deferring of a number of local transmission reinforcements in the San Diego area as discussed in chapter 2.

33 Percent RPS Generation Portfolios and Transmission Assessment

The transition to greater reliance on renewable generation has created significant transmission challenges because renewable resource areas tend to be located in places distant from population centers. The ISO's transmission planning process has balanced the need for certainty by generation developers as to where this transmission will be developed with the planning uncertainty of where resources are likely to develop by creating a structure for considering a range of plausible generation development scenarios and identifying transmission elements needed to meet the state's 2020 RPS. Commonly known as a least regrets methodology, the portfolio approach allows the ISO to consider resource areas (both in-state and out-of-state) where generation build-out is most likely to occur, evaluate the need for transmission to deliver energy to the grid from these areas, and identify any additional transmission upgrades that are needed under one or more portfolios. The ISO 33 percent RPS assessment is described in detail in chapters 4 and 5 of this plan.

In consultation with interested parties, CPUC staff developed three renewable generation scenarios for meeting the 33 percent RPS goal in 2020. The reduced number of scenarios from previous transmission planning cycles and less variability between several of the scenarios are indicative of less variability than in the past, as utilities move to complete their contracting for renewable resources to meet the 2020 goals, and there is more certainty about which areas resources will locate in.

In addition to transmission already approved by the ISO through the transmission planning process, the ISO considered Large Generator Interconnection Procedures (LGIP) network upgrades required to serve renewable resources that either have or were expected to have signed generator interconnection agreements.

The ISO assessment in this planning cycle did not identify at this time new major transmission projects to support achievement of California's 33 percent renewables portfolio standard given the transmission projects already approved or progressing through the California Public Utilities Commission approval process. Two smaller policy-driven transmission upgrades have been identified in this transmission plan, which the ISO is recommending for approval in this plan. The estimated cost of the two policy-driven projects is $135 million.

However, the deliverability of future renewable generation from the Imperial Valley area has been significantly reduced primarily due to changes in flow patterns resulting from the retirement of the San Onofre Nuclear Generating Station. Despite the impacts being heavily offset by other reinforcements proposed in this transmission plan, only 1000 MW of the 1715 MW of Imperial zone renewable generation portfolio amounts can be made deliverable. The change will also impact the ability to maintain deliverability of import capability from the Imperial Irrigation District at the intended level of 1400 MW. Given this significant change in circumstance, the ISO will conduct further study in the 2014-2015 transmission planning cycle to develop the most effective solution to achieve previously established target import capability levels..

The additional policy-driven projects identified in this cycle are:

- a 300 Mvar SVC at Suncrest, and
- a Lugo-Mohave series capacitor and related terminal upgrades

Table 2 provides a summary of the various transmission elements of the 2012-2013 transmission plan for supporting California's RPS in addition to providing other reliability benefits. These elements are composed of the following categories:

- major transmission projects that have been previously approved by the ISO and are fully permitted by the CPUC for construction;
- additional transmission projects that the ISO interconnection studies have shown are needed for access to new renewable resources but are still progressing through the approval process; and
- major transmission projects that have been previously approved by the ISO but are not yet permitted.

Table 2: Elements of 2013-2014 ISO Transmission Plan Supporting Renewable Energy Goals

Transmission Facility	Online
Transmission Facilities Approved, Permitted and Under Construction	
Sunrise Powerlink (completed)	2012
Tehachapi Transmission Project	2015
Colorado River - Valley 500 kV line (completed)	2013
Eldorado – Ivanpah 230 kV line (completed)	2013
Carrizo Midway Reconductoring (completed)	2013
Additional Network Transmission Identified as Needed in ISO Interconnection Agreements but not Permitted	
Borden Gregg Reconductoring	2015
South of Contra Costa Reconductoring	2015
West of Devers Reconductoring	2019
Coolwater - Lugo 230 kV line	2018
Policy-Driven Transmission Elements Approved but not Permitted	
Mirage-Devers 230 kV reconductoring (Path 42)	2014
Imperial Valley Area Collector Station	2015
Sycamore – Penasquitos 230kV Line	2017
Lugo – Eldorado 500 kV Line Re-route	2015
Lugo – Eldorado series cap and terminal equipment upgrade	2016
Warnerville-Bellota 230 kV line reconductoring	2017
Wilson-Le Grand 115 kV line reconductoring	2020
Additional Policy-Driven Transmission Elements Recommend for Approval	
Suncrest 300 Mvar SVC	2017
Lugo-Mohave series capacitors	2016

Economic Studies

Economic studies of transmission needs are another fundamental element of the ISO transmission plan. The objective of these studies is to identify transmission congestion and analyze if the congestion can be cost effectively mitigated by network upgrades. Generally speaking, transmission congestion increases consumer costs because it prevents lower priced electricity from serving load. Resolving congestion bottlenecks is cost effective when ratepayer savings are greater than the cost of the project. In such cases, the transmission upgrade can be justified as an economic project.

The ISO economic planning study was performed after evaluating all policy-driven transmission (i.e., meeting RPS) and reliability-driven transmission. Network upgrades determined by reliability and renewable studies were modeled as an input in the economic planning database to ensure that the economic-driven transmission needs are not redundant and are beyond the reliability- and policy-driven transmission needs. The engineering analysis behind the economic planning study was performed using a production simulation and traditional power flow software.

Grid congestion was identified using production simulation and congestion mitigation plans were evaluated through a cost-benefit analysis. Economic studies were performed in two steps: 1) congestion identification; and 2) congestion mitigation. In the congestion identification phase, grid congestion was simulated for 2018 (the 5th planning year) and 2023 (the 10th planning year). Congestion issues were identified and ranked by severity in terms of congestion hours and congestion costs. Based on these results, the five worst congestion issues were identified and ultimately selected as high-priority studies.

In the congestion mitigation phase, congestion mitigation plans were analyzed for the five worst congestion issues. In addition, two economic study requests were submitted. Based on previous studied, identified congestion in the simulation studies, and the study requests, the ISO identified 5 high priority studies, which were evaluated in the 2013-2014 planning cycle.

The analyses compared the cost of the mitigation plans to the expected reduction in production costs, congestion costs, transmission losses, capacity or other electric supply costs resulting from improved access to cost-efficient resources.

As in the 2012-2013 Transmission Plan, two projects in particular continued to demonstrate strong economic advantages – the Delaney-Colorado River 500 kV transmission line and the Harry Allen-Eldorado 500 kV transmission line. Both projects had been noted in the 2012-2013 Transmission Plan as needing further analysis.

Based on the continued analysis, the ISO is recommending proceeding with the Delaney-Colorado River[4] 500 kV transmission line. The estimated cost of this economic-driven project is $338 million.

The ISO's analysis of the Harry Allen-Eldorado line continues to show potential benefits. However, given NV Energy's recent announcement of its intent to join the ISO's energy

[4] The Delaney-Colorado River 500 kV line was not approved by the ISO Board of Governors at the March 20, 2014 ISO Board meeting.

imbalance market, we do not consider it prudent to move forward on a recommendation until this market change can be properly reflected in an economic analysis. The ISO intends to conduct this analysis as continued study work as part of this 2013-2014 transmission planning cycle, or continue the analysis into the 2014-2015 planning cycle if necessary.

Conclusions and Recommendations

The 2013-2014 ISO transmission plan provides a comprehensive evaluation of the ISO transmission grid to identify upgrades needed to adequately meet California's policy goals, address grid reliability requirements and bring economic benefits to consumers. This year's plan identified 31[5] transmission projects, estimated to cost a total of approximately $2.17[6] billion, as needed to maintain the reliability of the ISO transmission system, meet the state's renewable energy mandate, and deliver material economic benefits.

The transmission plan also identified three subjects which require further study; the latter two may result in management seeking additional Board approvals of certain amendments to the 2013-2014 transmission plan at a future meeting:

- continuing the coordinated and iterative process of addressing southern California (LA Basin and San Diego area) needs with an emphasis on preferred resources, as well as resolving remaining technical decisions regarding recommended solutions that contribute to the overall need.
- addressing the potential need for transmission reinforcement of the San Francisco Peninsula due to outage concerns related to extreme contingencies,
- reviewing the economic benefits of an Eldorado-Harry Allen 500 kV transmission line addition, once existing study work can be updated to reflect NV Energy's intention to participate in the ISO's Energy Imbalance Market.

[5] The number of projects approved in the 2013-2014 Transmission Plan is 30 with the removal of the Delaney-Colorado River project, which was not approved by the ISO Board of Governors at the March 20, 2014 ISO Board meeting.

[6] The estimated total cost is approximately $1.89 billion with the removal of the Delaney-Colorado River project, which was not approved by the ISO board of Governors at the March 20, 2014 ISO Board Meeting.

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