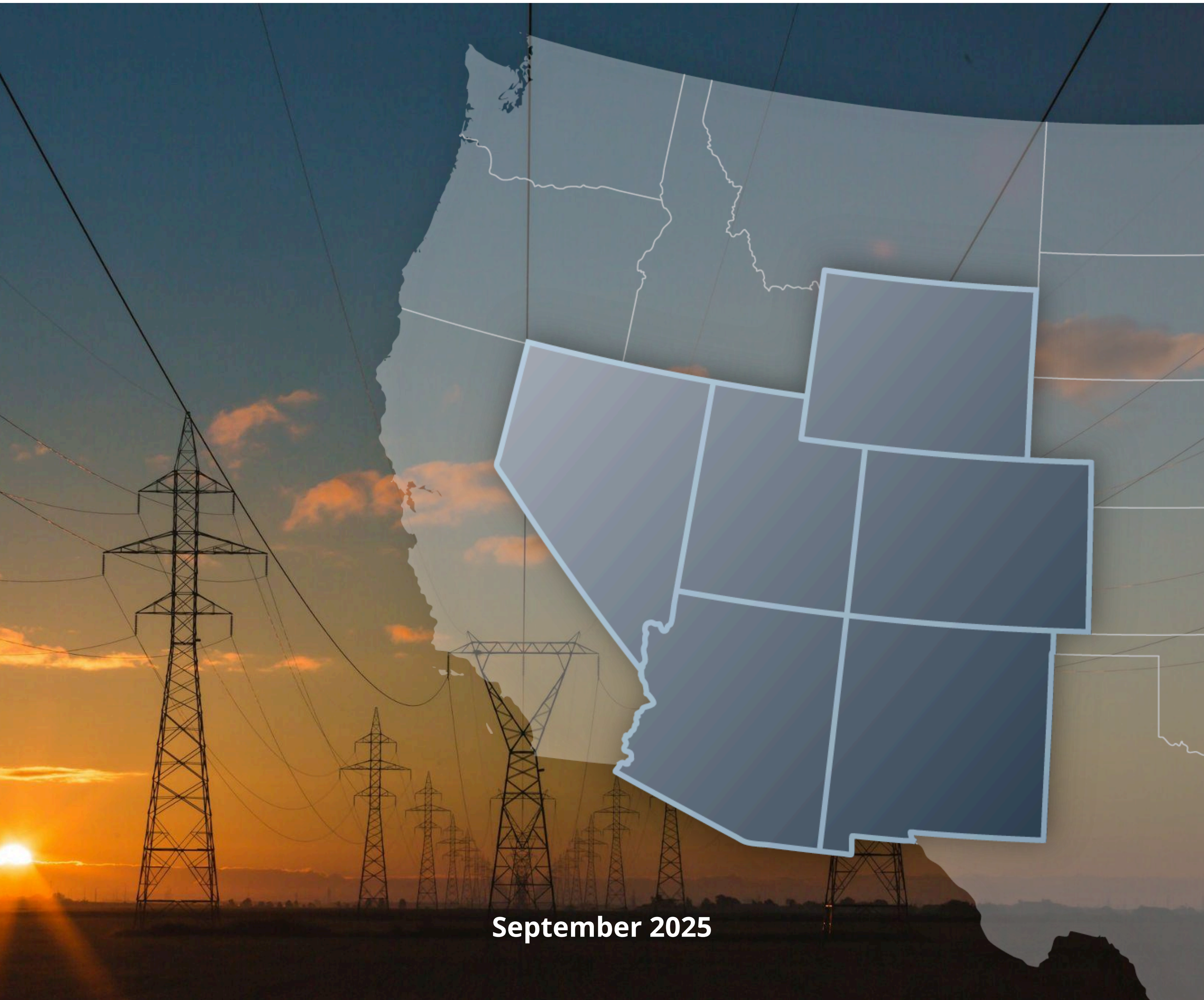
PART 2 of 2

Evaluating Transmission Opportunities in Integrated Resource Plans

Part 2: A Review of Interior West Utilities



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About Interwest Energy Alliance
Interwest Energy Alliance is a 501(c)(6) nonprofit regional trade association representing developers of large-scale renewable energy, storage, and transmission in six states in the Desert Southwest and Intermountain West. Interwest's mission is to create market opportunities for utility-scale renewables across the Interior West through policy and regulatory intervention.

Table of Contents

Case Studies

Executive Summary

Investor-owned utilities in the Interior West are tasked with maintaining reliable electric service at the lowest reasonable cost. As load growth accelerates and utilities interconnect more variable energy resources, delivering on this obligation increasingly demands innovation in how utilities plan. Yet many utilities still rely on legacy approaches to integrated resource planning that overlook the strategic role of transmission. The only way to plan effectively for a reliable, affordable, and clean grid is to integrate transmission into integrated resource plan (IRP) modeling and analysis.

This report is the second in a two-part series. In Part 1, we introduced five methods utilities can use to represent transmission constraints and quantify the value of transmission investments in IRP models. In this Part 2, we apply that framework to recent IRPs from Arizona Public Service (APS), NV Energy (NVE), PacifiCorp (PAC), Public Service Company of New Mexico (PNM), and Salt River Project (SRP). The result is a comparative ranking of these IRPs based on how comprehensively and effectively each evaluates transmission expansion opportunities.

Utility Rankings

The table below ranks recent IRPs and summarizes each utility's approach to the five methods for incorporating transmission. Approaches to each method range from red (no incorporation of transmission) to green (alignment with best practices).

Observed Methods for Evaluating Transmission Opportunities in IRPs

Rank	Utility & IRP	Resource Expansion Limits	Transfer Limits	Transmission Scenarios	Transmission Expansion Options	Transmission Planning Studies
1	PAC 2025 IRP	Green	Green	Yellow	Green	Yellow
2	PNM 2023 IRP	Yellow	Orange	Yellow	Yellow	Yellow
3	SRP 2023 IRP[1]	Orange	Red	Orange	Orange	Green
4	NVE 2024 IRP	Orange	Yellow	Green	Red	Orange
5	APS 2023 IRP	Orange	Red	Red	Yellow	Orange

[1] SRP has transitioned from an IRP to an "Integrated System Plan" (ISP). For simplicity, we use the term "IRP" to reference all utility resource planning processes, including SRP's.

Summary of Utility Evaluations and Recommendations

1. **PacifiCorp:** PAC's IRP models can select transmission upgrades and PAC's use of iterative modeling to account for production cost benefits is laudable. Future IRPs should include regional transmission options, evaluate more scenarios, include analysis of all relevant and planned transmission projects, and improve transparency by explaining how transmission options are selected and defined. PAC's score is relative and could be improved by more robustly analyzing all pertinent transmission projects.

2. **Public Service Company of New Mexico:** PNM's zonal production cost model and zonal transmission adders enable their capacity expansion model to select generation additions while accounting for transmission upgrade costs. Future IRPs should quantify the production cost value of new transmission and incorporate transmission costs in the evaluation of IRP portfolios. This may require additional intra-IRP transmission studies and use of a zonal capacity expansion model with transmission upgrade options.

3. **Salt River Project:** SRP uses transmission planning studies in their IRP to assess the cost of transmission upgrades when selecting a preferred portfolio. The next IRP should assign resource expansion limits comprehensively by zone and include zones with transfer limits in the production cost model. Once the models represent transmission constraints comprehensively, SRP should include additional transmission expansion options in the capacity expansion model and additional scenarios with specific transmission changes.

4. **NV Energy:** NVE's production cost model includes zones and transmission constraints, and NVE used one scenario to analyze the value of the planned Greenlink transmission upgrades. Future IRPs should include transmission constraints and new expansion options in the capacity expansion model and use scenarios to quantify the value of other (non-planned) transmission opportunities.

5. **Arizona Public Service:** APS mostly omits transmission constraints from IRP models. The next IRP should transparently explain APS's transmission analysis and modeling decisions, which should include representing all known and anticipated transmission constraints using additional resource expansion limits as well as zones with transfer limits in the production cost model. APS's next IRP should quantify the value of transmission upgrades using scenarios or transmission expansion options.

Regulatory commissions are uniquely positioned to require utilities to coordinate resource and transmission planning to ensure that IRPs identify prudent, cost-effective investments. By comparing examples from Interior West IRPs, we hope to demonstrate that more comprehensive approaches to planning are possible. Utilities that currently omit transmission from IRP modeling should look to others in the region who are already implementing the methods we detail in this report. Ultimately, progress should be measured by the extent to which IRPs adopt transparent, analytically sound methods for evaluating transmission, leading to more action plans that include transmission upgrades as part of the least-cost plan.

1. Introduction

This report is the second in a two-part series about how utilities should evaluate transmission expansion opportunities in integrated resource plans (IRPs).[2] In this second part, we provide a detailed review of five recent IRPs from utilities in the West and compare how well each evaluates transmission expansion opportunities. The utilities reviewed here are:

- Arizona Public Service (APS)
- NV Energy (NVE)
- PacifiCorp (PAC)
- Public Service Company of New Mexico (PNM)
- Salt River Project (SRP)

With many recent studies calling for significant investments in new transmission as the most cost-effective strategy for achieving a reliable electricity system, the consideration of transmission as an integral part of generation resource planning is increasingly important.[3] To assess whether utilities adequately consider transmission expansion in their IRPs, this report evaluates how effectively they apply five primary methods for incorporating transmission in IRPs (see *Section 2: Approaches to Evaluating Transmission in Recent IRPs*). Our goal in making this comparison is to demonstrate—with concrete examples—regional differences and industry best practices in IRP modeling and analysis.

After providing a detailed review of approaches to each method, we rank recent IRPs from best to worst and recommend improvements each utility should make in their next IRP (see *Section 3: Ranking and Utility-Specific Recommendations*). Readers focused on a specific utility may begin with Section 3 and return to Section 2 as needed for additional details.

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[2] In Part 1 of this report series, we reviewed the typical IRP modeling framework and described general methods utilities can use to incorporate transmission into their IRP models and scenario analysis. Readers interested in this introduction should start with Part 1 (*Evaluating transmission opportunities in integrated resource plans Part 1: How to incorporate transmission in IRP models*).

[3] Estimates suggest every $1 invested in well-planned, high-capacity transmission produces between $3.80 and $4.70 in benefits for U.S. consumers (Grid Strategies, *Large-Scale Transmission Deployment Saves Consumers Money*, 2025). Two high-voltage transmission portfolios approved through MISO's *Long-Range Transmission Planning* produced $2.60-$3.80 and $1.80-$3.50 in benefits for every $1 invested. Similarly, a review of seven operating regional and interregional transmission projects found ratepayers saved between $1.10 and $3.90 for every $1 spent, and savings exceeded planning estimates (RMI, *High Voltage, High Reward Transmission*, 2025). Modeling of the lower 48 U.S. states found that eliminating interregional transmission constraints would have reduced generation costs by $5.8–7.1 billion in 2022 and $3.4–5.0 billion in 2023 (Ham et al., *Power Flows Part 2: Transmission Lowers US Generation Costs, But Generator Incentives Are Not Aligned*, 2025).

This report's utility-specific recommendations build on five general recommendations for evaluating transmission in IRPs, which are presented in the companion Part 1 report and summarized in Table 1.

Table 1: General Recommendations for Evaluating Transmission in IRPs[4]

Method	Recommendation
Step 1: Represent Transmission Constraints in IRP Models	
Resource Expansion Limits in Capacity Expansion Models	Constrain new resource additions by zone based on known transmission capacity.
Transfer Limits in Production Cost Models	Apply transfer limits between load/resource zones and market zones to reflect known transmission constraints.
Step 2: Quantify the Value of Transmission Expansion Opportunities	
Transmission Scenarios	Model scenarios with specific transmission changes (e.g., new lines or rebuilds) to assess impacts on portfolio cost and composition.
Transmission Expansion Options in Capacity Expansion Models	Allow the model to exceed zonal limits by incurring costs that reflect necessary transmission upgrades.
Transmission Planning Studies Explicitly Integrated with the IRP Analysis	Use transmission planning studies to ensure that IRP models include accurate transmission constraints and upgrade options and that the final portfolio evaluation includes transmission costs required to deliver new resources.

Electricity industry modeling techniques are quickly advancing, and it is increasingly realistic to co-optimize generation and transmission planning. We encourage utilities that currently omit transmission to learn from others and promptly adopt approaches that

[4] Interwest Energy Alliance, *Evaluating transmission opportunities in integrated resource plans Part 1: How to incorporate transmission in IRP models*, 2025.

better evaluate transmission opportunities in their next IRP. Regulators and lawmakers also have essential roles to play in ensuring that IRPs identify a truly least-cost preferred plan, which is only possible if IRP models represent transmission constraints and IRP analysis evaluates transmission expansion opportunities. We hope this review encourages ongoing discussions about how to ensure IRPs deliver the most cost-effective strategies as utilities work to meet the evolving needs of the grid.

2. Approaches to Evaluating Transmission in Recent IRPs

Through a detailed review of five utilities' recent IRPs, we identified five common methods for representing transmission constraints in capacity expansion and production cost models and then quantifying the value of transmission expansion options.[5] These methods are:

1. **Resource expansion limits** in capacity expansion models,
2. **Transfer limits** in production cost models,
3. **Transmission scenarios**,
4. **Transmission expansion options** in capacity expansion models, and
5. **Transmission planning studies** explicitly integrated with the IRP analysis.

For each method, we explain the range of approaches used in recent IRPs, which approaches are most effective, and why. We also provide specific examples and case studies of exemplary approaches.

A summary of our analysis is shown in Table 2 (next page), which depicts a spectrum of approaches for each method, from omitting transmission entirely to including it comprehensively. These ranges provide the basis for how this report ultimately ranks the IRPs. The utilities that use each approach are listed at the bottom of each relevant table cell. The approaches in green are the most comprehensive, but we acknowledge that does not necessarily mean they are the best next step for every utility. Instead, we encourage utilities that currently omit transmission (or incorporate transmission only partially) to adopt more comprehensive approaches.

After reviewing the spectrum of approaches utilities take with each method, this report ranks utilities based on an overall assessment of how effectively their latest IRP evaluates transmission expansion opportunities (see *Section 3: Rankings and Utility-Specific Recommendations*). The overall rankings are derived from our analysis of each method. The rankings reflect that evaluating transmission expansion opportunities in an IRP is only possible if the utility first sets up the IRP models to include the significant transmission constraints on their system. Some utilities do not currently take this necessary first step. Once the capacity expansion and production cost models contain the important transmission constraints, utilities can use scenarios and transmission expansion options to quantify the costs and benefits of potential upgrades.

[5] For an introduction to these methods, see Interwest Energy Alliance, *Evaluating transmission opportunities in integrated resource plans Part 1: How to incorporate transmission in IRP models*, 2025.

Table 2: Approaches to Evaluating Transmission in Recent IRPs[6]

Method	← Transmission Omitted			Transmission Incorporated →
Step 1: Represent Transmission Constraints in IRP Models				
Resource Expansion Limits in Capacity Expansion Models	No candidate resources limited by transmission	Single-resource limits **APS, NVE, SRP**	Comprehensive zonal limits **PNM**	Model can select transmission upgrades to exceed limits **PAC**
Transfer Limits in Production Cost Models	No internal zones with transfer limits **APS, SRP**	Multiple internal zones with transfer limits **PNM**	Limits change to reflect planned upgrades **NVE**	Model can add transmission to change limits **PAC**
Step 2: Quantify the Value of Transmission Expansion Options				
Transmission Scenarios	No transmission scenarios **APS**	Scenarios with generic transmission changes **SRP**	Scenarios with specific transmission changes **PAC, PNM**	Scenarios evaluate transmission portfolios **NVE**
Transmission Expansion Options in Capacity Expansion Models	No transmission expansion options **NVE**	Transmission cost adders for single resources **SRP**	Transmission cost adders for all resources by zone **APS, PNM**	Transmission upgrade options with a zonal model topology **PAC**
Transmission Planning Studies Explicitly Integrated with the IRP Analysis	No use of transmission planning studies in IRP	Transmission planning studies inform IRP model constraints **APS, NVE**	Transmission planning studies directly inform upgrade options **PAC, PNM**	Transmission planning studies re-examine IRP model results **SRP**

[6] This analysis considers the following IRPs: Arizona Public Service's (APS) 2023 IRP, NV Energy's (NVE) 2024 IRP, PacifiCorp's (PAC) 2025 IRP, Public Service Company of New Mexico's (PNM) 2023 IRP, and Salt River Project's (SRP) 2023 Integrated System Plan (ISP); see *References*. Note: We exclude Public Service Company of Colorado (PSCo) from this report because much of their transmission modeling occurs in the procurement phase of their two-phase linked IRP and resource acquisition process, and is therefore outside the typical IRP's scope.

2.1. Resource Expansion Limits

To incorporate transmission constraints in a capacity expansion model, utilities can limit the quantity (MW) and timing (first available year) of candidate generation options to reflect the transmission system's ability to deliver new resources to load. The approaches for using these resource expansion limits range from an ad hoc application of limits on only one or two resource types to applying comprehensive limits to all resources by zone. The comprehensive zonal approach is better because it accounts for constraints limiting the delivery of all generation types in all areas of the system with limited transmission capability. Some utilities also ensure the resource options and limits reflect available information from the interconnection queue, or conduct studies explicitly designed to inform the IRP.

Table 3: Resource Expansion Limits in Capacity Expansion Models

Model can select upgrades to exceed limits
Comprehensive zonal limits
Single-resource limits
No candidate resources limited by transmission

Utility	Resource Options Limited by Transmission Constraints	Approach
PAC	All 19 generation resource zones have quantity limits, and the capacity expansion model can exceed limits by selecting transmission upgrade options.	
PNM	All five generation resource zones have quantity limits. Additionally, Eastern NM wind is limited to 1,000 MW beginning in 2033.	
APS	All Arizona resources have the same quantity limit. Additionally, New Mexico wind (the only out-of-state resource) is limited to 1,900 MW beginning in 2032.	
SRP	Only California geothermal and wind are limited. Five wind options are defined with different quantity and timing limits.	
NVE	Only Idaho wind is limited (to 952 MW beginning in 2029).	

Single-Resource Limits

APS, NVE, and SRP each apply expansion limits to specific wind and geothermal resource options (e.g., "New Mexico Wind" or "California Geothermal").[7] For all three, the limits are based on assumptions about available transmission to access these resources, which are typically located in other states.

[7] APS 2023 IRP, "Reference Case," p. 72; SRP 2023 ISP, "Resource Additions," pp. 73-79; NVE 2024 IRP, Vol. 8 "New Idaho Wind PPA," p. 225.

Of these utilities, SRP's approach is more thorough. SRP defines one geothermal option and five different wind options, and explains the timing and quantity limits for each based on the assumed transmission availability. For example, SRP allows their model to select up to 1,000 MW of geothermal beginning in 2031. These quantity and timing limits reflect SRP's assumption that accessing this resource would require time to develop new transmission to deliver the energy and capacity from Salton Sea, CA to Phoenix, AZ. Similarly, SRP gives their model the option to select up to 100 MW of Wyoming wind based on the assumption that 100 MW of transmission could become available in 2029 following the retirements of the Craig and Hayden coal plants. While SRP effectively applies transmission limits to individual resource options, they omit broader transmission constraints that impact all generation types.

APS applies a single-resource limit to New Mexico wind and also limits the total quantity of Arizona resource additions to reflect the current transmission system's ability to deliver in-state resources to load. Although APS applies resource expansion limits to all resources, modeled transmission constraints only differentiate New Mexico wind from all other resource options (which are subject to the same constraint).

Comprehensive Zonal Limits

PAC and PNM use a zonal approach in their models to limit the total quantity of resource additions on different parts of their system based on available transmission.[8] This zonal approach is better than limiting single resources because it accounts for transmission constraints that may restrict the delivery of all types of generation in specific locations. Including multiple zones with different limits allows the model to prioritize selection of resources in areas that do not require transmission upgrades for delivery.

Furthermore, APS, PAC, PNM, and SRP allow their models to select resources over the resource expansion limits by incurring a cost representing the transmission upgrades that could raise the limits. The resources chosen by these utilities' capacity expansion models therefore account for the costs of transmission system upgrades required to interconnect and deliver those resources. Approaches to including transmission expansion options in capacity expansion models differ in significant ways that we discuss in *Section 2.4*.

Using Information from the Interconnection Queue

PAC takes the positive, extra step of using information from recent interconnection requests to determine the quantity and fuel type of near-term resource expansion

[8] PAC 2025 IRP, "Long-Term (LT) Capacity Expansion Model," pp. 188-191; PNM 2023 IRP, Section 7.2.2. (Findings from phases 1 & 2 analyses), p.175.

options.[9] This use of interconnection queue data ensures that the modeling set-up accurately reflects a realistic set of generation expansion opportunities.

Recommendation: APS, NVE, and SRP should define multiple zones in their capacity expansion models and limit the type, quantity, and timing of new resources in each zone to reflect deliverability. The models should then be enabled with the option to exceed transfer limits at a cost (see *Section 2.4*).

[9] PAC 2025 IRP, Public Input Meetings (May 2, 2024), "Transmission Modeling Strategy," slides 54-60; (June 26-27, 2024), "Transmission Interconnection Options," slides 97-105; (August 14-15, 2024), "Transmission Option Dependencies," slides 58-62.

2.2. Transfer Limits

Utilities can represent transmission constraints in production cost models by segmenting the utility's generation and loads into multiple zones and defining limits on the maximum quantity (MW) of power the model allows to flow between zones at any given time. The use of transfer limits we observed varies primarily in the number of zones modeled. All zonal models are simplifications of the transmission system, and the number of zones should be tailored to the utility's system.[10] However, models with multiple zones and transfer limits that change (to reflect known future upgrades) can better simulate system operations.

While utilities that serve a single metro area may not need as many internal zones as multi-region utilities, all IRP production cost models should include some internal zones to represent transmission constraints unless the utility truly has no internal constraints that impact their generation dispatch. After establishing transfer limits, the best IRPs go further by quantifying the production cost benefits of relaxing transfer limits and allowing the model to adjust limits by selecting transmission upgrades as part of the least-cost solution.

Table 4: Transfer Limits in Production Cost Models

Model can add transmission to change limits ■
Limits change to reflect planned upgrades ◪
Multiple internal zones with transfer limits ◩
No internal zones with transfer limits ☒

Utility	# Utility (Internal) Zones	# Market Zones	Limits Change With Planned Upgrades	Production Cost Impact Analyzed	Approach
PAC	25	7	Yes	Yes	■
NVE	6	4	Yes	Yes	◪
PNM	6	2	No	No	◩
APS	1	1	No	No	☒
SRP	1	1	No	No	☒

No Internal Zones

APS and SRP do not include any internal transmission constraints in their production cost models.[11] While transmission constraints may not be as impactful for these utilities that

[10] None of the utilities we reviewed use nodal production cost models.
[11] APS 2023 IRP, "Production Cost Modeling (PCM)," p. 66; SRP 2023 ISP, "Resource Operations," p. 84.

serve a single primary load center (e.g., Phoenix), unless they expect no constraints on their system will impact dispatch at all for the full duration of the planning horizon, known and anticipated future constraints should be included and used to define internal zones. For example, APS's 2023 IRP forecasts that, due to the rapid influx of large commercial, industrial, and data center load, existing transmission capacity will be consumed before the end of the decade (well within the utility's 15-year planning horizon).[12] Furthermore, APS' 2023 all-source request for proposals includes a map of eight resource zones on the utility's Arizona system and indicates that deliverability from all zones is either limited or location-dependent.[13] APS should use these zones to account for anticipated transmission constraints in their production cost model in the next IRP.

Multiple Internal and Market Zones

NVE, PAC, and PNM configure their production cost models with multiple zones with transfer limits, providing models that the Arizona utilities could adopt.[14] For example, PNM's model contains a primary load zone (representing the greater Albuquerque area), a secondary load zone (representing customers in PNM's southern service territory), and five resource zones: North, East, South, West, and Load Side. PNM also models market hubs at Four Corners and Palo Verde. Each utility and market zone is connected by transfer limits representing transmission constraints. Similarly, NVE's production cost model defines a northern and southern load zone and several resource and market zones. PAC, meanwhile, includes over 30 zones, an approach that effectively models energy dispatch on their 18,000-mile transmission system spanning five states.

Transfer Limits that Change

Including multiple zones with transfer limits is a necessary first step to incorporating transmission constraints in IRP production cost models, but some utilities go further. NVE represents planned transmission upgrades by changing transfer limits over time. PAC adds additional flexibility by configuring their production cost model so that transfer limits change if the capacity expansion model selects transmission upgrades that increase transfer capability between zones.[15] Connecting transmission upgrades chosen by the capacity expansion model to transfer limits in the production cost model is essential to capture both the costs and benefits of adding transmission as part of the IRP portfolio.

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[12] APS 2023 IRP, "Transmission," p. 49.

[13] APS All-Source RFP, "Appendix F - Deliverability Map," p.57.

[14] PNM 2023 IRP, Public Advisory Meeting (Oct. 6, 2022), "2020 IRP Topology – Zonal Modeling," slide 20; NVE 2024 IRP, Vol. 28, "Zonal transmission model in PLEXOS," p. 320; PAC 2025 IRP, Fig. 8.3 (Transmission system model topology with major options), p. 190.

[15] See *Case Study 2*.

Improving How Import Limits Are Defined

There is room for all utilities to improve how they define transfer limits between market and utility zones. PAC restricts market purchases in the production cost model during specific hours to account for limited market depth.[16] However, none of the other IRPs we reviewed specifies whether the modeled import and export limits reflect assumptions about transmission constraints, market depth, or both. Combining these assumptions into a single limit makes it challenging to analyze the value of new transmission between utility systems, which is increasingly important as utilities join day-ahead markets and resource adequacy agreements to share resources as a region more efficiently. Modeling transmission constraints as import and export limits will enable IRPs to evaluate the value of expanding transmission connections to neighboring systems.

Quantifying Production Cost Impacts

Finally, including transfer limits enables utilities to quantify the impact of transmission constraints on production costs, which is essential to accurately evaluate the full benefits of transmission options considered in the IRP. However, of the IRPs we reviewed, only NVE and PAC attempt to quantify these impacts.[17] PNM does not quantify or report the production cost impacts or magnitude of resource curtailments created by transmission constraints, and APS and SRP do not represent any internal transmission constraints in their production cost models (which is a pre-requisite to quantifying their impact). Utilities should report the impacts that transmission constraints have on limiting dispatch (constrained hours, energy (MWh) curtailed, etc.) and the production cost impacts of the constraints for each IRP portfolio modeled. Quantifying these impacts is the first step toward analyzing how transmission investments could impact production costs, which is necessary to evaluate transmission expansion opportunities accurately.

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[16] In this context, "market depth" refers to the maximum volume of wholesale energy that the utility could expect to purchase from other utilities or market participants; see PAC 2025 IRP, "Market Purchases," pp. 178-179.

[17] NVE and PAC take very different approaches to calculating the production cost value of the new transmission. PAC uses iterative modeling that calculates congestion along transmission paths and applies a credit to incentivize selection of transmission upgrades that reduce production costs; see *Case Study 2*. NVE calculates the production cost impact of not building their planned Greenlink transmission upgrades by running a scenario with reduced transfer limits; see *Case Study 1*.

Recommendations:

- APS and SRP should include multiple internal zones with transfer limits in their production cost models.
- All utilities should ensure that transfer limits are relaxed in their production cost model if transmission expansion options are selected in the capacity expansion model (only PAC does this currently; see *Section 2.4*).
- All utilities should publish the number of hours that transmission constraints limit dispatch and the cost of these constraints for each IRP portfolio modeled.
- All utilities should clarify how external transmission constraints limit modeled imports and exports.

2.3. Transmission Scenarios

Transmission scenarios are a straightforward way to quantify the economic value of a transmission investment by comparing the total cost of IRP portfolios created with and without a transmission upgrade in place. However, they are rarely used in IRPs. Of the 104 total scenarios in the five IRPs we reviewed, only nine included variation in transmission (Table 5). Utilities should include more transmission scenarios in IRPs to ensure they adequately integrate transmission expansion options into the assessment of least-cost generation portfolios.

Table 5: Proportion of IRP Scenarios with Transmission Variation

Utility	APS	NVE	PAC[18]	PNM	SRP	Total
Total # IRP Scenarios[19]	14	5	24	47	14	104
# Transmission Scenarios	0	1	2	4	2	9
%	0%	20%	8%	9%	14%	12%

Specific vs. Generic Transmission Changes

There is a distinct range of usefulness among the IRP scenarios that include variation in transmission assumptions (summarized in Table 6 below). The most useful scenarios include *specific transmission changes* reflected in varied assumptions about specific conceptual transmission upgrades informed by studies from the utility's transmission planning team. Other transmission scenarios include *generic transmission changes,* or adjusted model inputs indirectly related to transmission, which are used as a proxy for general assumptions about transmission expansion.

Scenarios that use generic proxies are of limited value. For example, SRP's regional diversity scenario lowers the planning reserve margin (PRM) from 16% to 13% as a proxy for increased regional transmission and coordination. Predictably, this reduces the need for firm capacity resources on SRP's system and reduces system costs.[20] Transmission scenarios with such generic changes can help illustrate general system dynamics and may

[18] Because PAC's capacity expansion model can select transmission upgrades, any IRP scenario that requires selection or removal of a candidate generation resource may also indirectly change transmission options. Tables 5 and 6 only include scenarios that directly change transmission assumptions relative to other scenarios.
[19] When counting IRP scenarios, we included all distinct portfolios and sensitivities.
[20] SRP 2023 ISP, "Regional Diversity," p. 144.

help produce rough estimates of what might reflect the appropriate budget for regional transmission investments to lower the utility's PRM (based on the cost savings enabled by a reduced PRM). However, they are overly general to evaluate specific transmission investments and therefore rarely actionable. Furthermore, SRP does not explain the choice to assess a 3% PRM reduction. Utilities that use proxies should offer analytical support for the assumptions chosen.

Scenarios with specific transmission changes are much better for quantifying the value of transmission expansion options. For example, PNM modeled a scenario in which transmission to access 1,000 MW of Eastern New Mexico wind became available five years earlier than in other scenarios. This change in timing reduced PNM's 30-year net Present Value of Revenue Requirement (PVRR) by $114 million, showing that expedited transmission development reduced system costs.[21] NVE and PAC also included transmission scenarios with specific transmission changes. These transmission scenarios are valuable for informing planning decisions about whether and when to invest in grid infrastructure that enables access to cost-effective resources.

Evaluating Portfolios of Transmission Upgrades

NVE's "No Greenlink" scenario demonstrates how planners might use scenarios to comprehensively evaluate a portfolio of transmission upgrades alongside generation resource investments. By running their IRP models without Greenlink's portfolio of additional transfer capability, NVE illustrated that, despite recent cost increases, removing the project would increase system costs by at least $830 million over a 26-year planning horizon.[22]

Recommendation: All utilities should include more IRP scenarios to evaluate specific conceptual transmission upgrades studied by the transmission planning team. NVE's "No Greenlink" scenario demonstrates how utilities can use IRP scenarios to evaluate transmission investment portfolios and understand their impact on the generation portfolio's composition, cost, and performance.

[21] PNM 2023 IRP, Table 56 (Select cases with and without early wind expansion), p. 175.

[22] The "No Greenlink" illustrative case was not evaluated as a full IRP scenario, but it nevertheless exemplifies how utilities might use IRP scenarios to evaluate portfolios of transmission upgrades; see *Case Study 1*.

Table 6: Transmission Scenarios

Transmission portfolios evaluated
Specific transmission changes
Generic transmission changes
No transmission scenarios

Utility	Scenario Description	Model Changes	Results	Approach
NVE	**No Greenlink:** illustrates a future in which the Greenlink transmission projects are not constructed[23]	Removes assumed transmission and reduces transfer limits; increases Sierra PRM 13% to 18%; changes resource options	2024-2050 PWRR increased by $830M; 7,900 MW more installed capacity (storage, solar, and thermal replace NV wind); higher CO2 emissions	
PNM	**Early Wind Expansion:** accelerated transmission development enables earlier access to Eastern NM wind[24]	1,000 MW Eastern NM wind available in 2028 vs. 2033	2023-2053 PVRR reduced by $114 million in the Base Technologies scenario	
PAC[25]	**Offshore Wind (OSW):** assumes 1,000 MW of OSW and associated transmission developed in 2030	Forces selection of OSW and required transmission in 2030	2024-2045 PVRR increased by $8.2B; 2,971 MW more installed capacity (wind/storage; less solar/storage)	
	WA Maximum Customer Benefit: prevents transmission development in two WA counties	Removes Yakima and Walla Walla transmission options; other changes	Less wind; more energy efficiency; utility-scale solar replaced with small-scale	
SRP	**Regional Diversity:** assumes regional transmission and coordination increase resource diversity[26]	Reduces PRM 16% to 13% (338 MW reduction by 2035)	Reduces total system costs and emissions	
	Strong Climate Policy: assumes federal policy guides economy-wide net-zero emissions by 2050 and increased regional transmission[27]	Reduces PRM 16% to 13%; makes geothermal available in 2029 (vs. 2031) and accelerates emerging technology	Increases installed capacity (solar/wind/storage) and transmission investments	
APS	None	N/A	N/A	

[23] NVE 2024 IRP, Vol. 3 (Tsoukalis testimony), pp. 290-316; Vol.4 (Williams testimony), pp. 115-124; Vol.8 (Supply plan narrative), pp. 295-308.
[24] Early wind expansion reduces the PVRR by $114M in the Base Technologies case and between $20M and $402M in other cases; see PNM 2023 IRP, Table 56 (Select cases with and without early wind expansion), p. 175.
[25] PAC 2025 IRP, "Force Offshore Wind," p. 266; "Washington Portfolios," p. 211; Vol. 2, App. O. (Washington clean energy action plan), p .473.
[26] SRP 2023 ISP, "Regional Diversity Sensitivity," pp. 144-145.
[27] SRP's "Strong Climate Policy" scenario assumes additional changes such as higher levels of electrification and distributed generation, and lower technology costs; see SRP 2023 ISP, pp. 55-59, 76-78, 176.

Case Study 1: NV Energy's "No Greenlink" Scenario

NVE's 2024 IRP includes a "No Greenlink" scenario to calculate the customer savings created by the planned Greenlink Nevada transmission upgrades, despite cost increases.[28] Greenlink is a set of new high-voltage transmission lines and substations that increase transfer capabilities between NVE's northern (Sierra Pacific Power) and southern (Nevada Power) systems while unlocking renewable energy resource zones and increasing market access in the Western U.S. To create the scenario, NVE compared their IRP preferred plan to a new model that assumed a counterfactual future in which Greenlink is not built. This was accomplished by reducing transfer limits between zones, increasing Sierra's PRM from 13% to 18%, and omitting generation additions that required Greenlink to interconnect.

This "No Greenlink" scenario showed that not building these planned transmission upgrades would lead to higher system costs and greater reliability risks. **Without Greenlink:**

- NVE requires 7,900 MW more installed capacity over the 26-year study period;
- Total system costs are $830 million higher than in the IRP preferred plan;
- The system experienced higher levels of unserved energy risk in the 2030s; and
- Carbon dioxide emissions are higher due to reduced access to renewable energy resources.

By explicitly modeling a future without major transmission investments, NVE demonstrates how utilities can use IRP scenarios with and without transmission upgrades to quantify the value of transmission expansion. While NVE included the "No Greenlink" scenario to illustrate the continued value of a project already under development, their analysis demonstrates how utilities could use IRP scenarios to proactively study conceptual transmission upgrades in the IRP.

[28] NVE 2024 IRP, Vol. 3 (Tsoukalis testimony), pp. 290-316; Vol.4 (Williams testimony), pp. 115-124; Vol.8 (Supply plan narrative), pp. 295-308; for general information see NV Energy, *Greenlink Nevada*.

2.4. Transmission Expansion Options

Both transmission cost adders and transmission upgrade options are effective ways to enable a capacity expansion model to jointly evaluate candidate generation and transmission investments when determining the least-cost portfolio. Transmission cost adders can be used in a capacity expansion model without defined zones. In contrast, transmission upgrade options can be directly specified in a capacity expansion model that uses a zonal framework. Only PAC used transmission upgrade options. PNM used zonal transmission cost adders, APS used a single transmission adder for all Arizona resource options and a different cost adder for New Mexico wind, SRP used only single-resource cost adders (for five wind options and one geothermal option), and NVE omitted any transmission upgrade options. A comprehensive multi-zone approach (using adders or upgrade options) is better than cost adders for single resources. In all cases, utilities should justify transmission cost assumptions and set up models to offset costs with economic transmission benefits such as production cost savings.

Table 7. Transmission Expansion Options

Transmission options with a zonal model topology
Cost adders for all resources by zone
Cost adders for single resources
No transmission expansion options

Utility	Transmission Expansion Options	Cost Estimates	Approach
PAC	12 transmission upgrade options in PAC-E and 17 options in PAC-W[29]	Available only in confidential workpapers	
PNM	Cost adders for resources in five different zones (North, South, East, West, Loadside)	$304 - $901/kW adder based on unit costs of modeled upgrades	
APS	One cost adder for all AZ resource options and a different adder for NM wind	Not specified	
SRP	Cost adders for five wind options (NM, AZ & WY new & existing transmission) and CA geothermal	$0 - $139/kW-yr adder	
NVE	None	N/A	

Adders for Single Resources

While SRP incorporates transmission upgrades associated with specific wind and geothermal options, they omit constraints and upgrade options that affect other new

[29] PAC 2025 IRP, Public Input Meeting (Sept. 25, 2024), "Transmission Options," slides 56-60.

resource additions. Using comprehensive adders applied to multiple zones is better because it assigns the same transmission cost adder to all resource options within a defined area based on the estimated cost of transmission upgrades needed to deliver power from that zone. Defining multiple zones and applying adders comprehensively across zones ensures the model has a realistic cost signal for all new generation options.

Adders Applied Comprehensively by Zone

APS applies transmission costs to all candidate resource additions once the model exceeds the current transmission system's ability to deliver new resources to load, but resource limits and transmission costs are only differentiated for New Mexico wind (all other resource options, assumed to be in Arizona, receive the same transmission costs). APS's use of a single generic transmission adder for all in-state resource options allows their capacity expansion model to account for a rough estimate of transmission upgrade costs to deliver a portfolio, but it doesn't include multiple transmission upgrade options the model can evaluate alongside candidate generation investments when determining the least-cost portfolio.

PNM's approach using multiple zones is effective and easily understood, providing a helpful reference point for comparison. PNM's transmission team identified seven conceptual transmission projects that would increase deliverability to the utility's primary load zone, containing the greater Albuquerque area.[30] Five transmission upgrades directly informed transmission cost adders based on their $/kW unit costs (capital cost divided by increased transfer capability), and several load-side upgrades were averaged to create an adder applied to up to 300 MW of load-side resources. In southern NM, where no conceptual projects were modeled, PNM assigned a $901/kW adder based on a weighted average cost of the conceptual projects evaluated. PNM's use of transmission adders is effective because it:

- Applies adders to all resources by zone;
- Bases cost estimates on specific conceptual projects studied by the transmission planning team; and
- Differentiates resource options zonally based on transmission upgrade costs.

Transmission Upgrade Options

PAC's approach adds further complexity by using a zonal topology in their capacity expansion model and defining transmission upgrade options that the model can select alongside generation additions.[31] As with PNM, PAC's transmission planning team defines

[30] PNM 2023 IRP, Sec. 6.5.2 (Transmission system upgrades), pp. 150-154.
[31] PAC 2025 IRP, "Transmission Options," pp. 190-192.

potential transmission upgrades that would enable additional generation resources in specific zones. However, rather than assign a unit cost to resources in each zone, PAC includes transmission upgrades as discrete options that the model considers when constructing a least-cost portfolio. Transmission and generation additions are separate but linked because adding generation beyond the existing system's capabilities requires the capacity expansion model to also select necessary transmission upgrades and incur the associated costs.[32]

Using transmission upgrade options rather than cost adders more accurately represents potential transmission upgrades, partly because the model must select a complete upgrade to unlock access to associated generation. In contrast, utilities that use cost adders typically allow the model to choose any quantity (MWs) of generation, including a per-MW transmission adder. This means the optimal portfolio might include only partial selection of a transmission upgrade. Such an outcome requires further analysis and produces less actionable results. A zonal capacity expansion model also enables loads to be defined distinctly in each zone (in addition to generation), which more accurately represents system operations. Overall, using a zonal topology with transmission upgrade options sets up a more realistic co-optimization exercise than using transmission cost adders.

Planned vs. Conceptual Transmission Projects

Transmission expansion options are only an effective evaluation tool if they accurately reflect the costs of the candidate investments and their impacts on transfer capacity. Ideally, cost adders should be based on specific conceptual transmission upgrades the transmission planning team has studied (such as in PNM's approach). However, this raises the question of when utilities consider transmission investments "planned" (versus "conceptual").[33] Interior West utilities take different approaches. NVE includes the planned Greenlink transmission lines as fixed changes to modeled transfer limits at future dates that reflect the expected completion of the new transmission lines[34]. In contrast, PAC includes even near-term, planned transmission projects as *options* in their capacity expansion model (with a low cost given investments already made), so the IRP continues to "select" these upgrades with each cycle.[35] Regardless of the approach, IRPs should clearly state the status of transmission options considered in the IRP and explain why the utility

[32] See *Case Study 2*.

[33] Most utilities consider a project planned when it has an approved budget to initiate permitting or other pre-construction activities. While the terms "planned" and "conceptual" are used in most utility planning, there is no official definition or industry standard for when a project becomes "planned."

[34] NVE 2024 IRP, Vol. 28, "Zonal transmission model in PLEXOS."

[35] PAC 2025 IRP, Response to Stakeholder Feedback (February 24, 2025), No. 2025.064 IEA 2-10-2025.

included the set of candidate upgrades they use and how they arrived at the associated cost estimates.

Inter-Jurisdictional Transmission as a Capacity Resource

Most transmission options evaluated in IRPs reflect upgrades on a single utility's system. However, inter-jurisdictional transmission (between two utilities or Balancing Authority Areas) is becoming more critical as utilities join day-ahead markets and regional resource adequacy programs. One way to evaluate inter-jurisdictional transmission expansion options in an IRP is to assess whether or not they merit a capacity accreditation. This would apply to transmission expansion that increases access to areas with a generation mix that is sufficiently large or diverse that it could improve the resource adequacy position of the utility in question. For example, Idaho Power models the SWIP-North transmission line as a 500 MW winter capacity resource in their IRP because it connects Idaho Power to the desert southwest, which produces abundant excess energy during the winter months.[36] However, none of the IRPs we reviewed modeled transmission as a capacity resource (Idaho Power was not part of our analysis for this report).

The ability of interregional transmission to serve as a capacity resource was also raised by intervenors in Public Service Company of Colorado's (PSCo) 2024 IRP. In response, PSCo studied a scenario that added an interregional transmission line with market purchases allowed for capacity. This scenario reduced PSCo's Present Value of Revenue Requirements by approximately $6 billion compared to the Base Plan.[37] However, PSCo chose not to include interregional transmission as a capacity resource in its IRP modeling, citing concerns that overreliance on market access creates economic and reliability risks.[38] While PSCo is also not part of our analysis, this scenario illustrates one way to evaluate transmission as a capacity resource. In future IRPs, utilities should evaluate regional and interregional transmission upgrades for their potential capacity contributions, to the extent that the possible expansion options increase access to markets with sufficient depth or diversity.

Quantifying Production Cost Benefits

Finally, transmission cost adders should be offset by production cost savings the transmission upgrade would enable (if they exist). However, among the IRPs we reviewed, only PAC's accounts for the production cost savings enabled by transmission expansion. We

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[36] Curtis Westhoff, *Idaho Power Transmission Update* (March 13, 2025).
[37] Derek Stenclik, *Public Answer Testimony of Derek Stenclik on behalf of the Conservation Coalition*, Hearing Exhibit 801, Proceeding No. 24A-0442E (April 18, 2025), p. 44.
[38] John Landrum, *Supplemental Direct Testimony of John Landrum on behalf of Public Service Company of Colorado*, Hearing Exhibit 111, Proceeding No. 24A-0442E (February 21, 2025), pp. 80-97.

urge the other utilities to improve in this regard. Assessing the production cost savings from transmission expansion can be accomplished using iterative modeling in which production costs captured in the dispatch simulation are applied as a credit to incentivize selection of those upgrades in the capacity expansion model.[39] Then, any changes in the capacity expansion model's selection of transmission options can be evaluated in another iteration of the production cost model. As a baseline, utilities should ensure that transmission upgrades selected in the capacity expansion model are included as relaxed transfer limits in the production cost model.

Recommendations:

- APS, NVE, and SRP should either apply transmission cost adders to all resources comprehensively using multiple zones or use a zonal capacity expansion model with transmission upgrade options.
- All utilities should consider a zonal transmission topology with transmission upgrade options in their capacity expansion models in future IRPs.
- All utilities should consider including regional and interregional transmission upgrades as a capacity resource.
- All utilities should offset the cost of transmission expansion options with production cost savings (PAC's approach is effective, and other methods may also be used).
- All utilities, including PAC, should provide more transparent explanations of how they arrive at the transmission expansion options and associated cost estimates included in their IRPs.

[39] PAC 2025 IRP, "Granularity Adjustment Detail," pp. 185-186; see *Case Study 2*.

Case Study 2: PacifiCorp's Co-Optimization of Transmission and Resource Expansion

PAC's 2025 IRP features two notable modeling innovations that enable it to evaluate transmission expansion opportunities: transmission options in the capacity expansion model, and an iterative modeling framework that accounts for the production cost value of new transmission.

Transmission Options in PAC's Capacity Expansion Model

Instead of applying transmission cost adders like other utilities we reviewed, PAC defines transmission upgrade options—each with a cost, available year, and capacity increase—that the model can select alongside new generation resource options.[40] These transmission options achieve a similar result as zonal transmission adders, but use a more advanced, modeling-heavy approach.

The model includes two types of transmission upgrades:

1. Interconnection upgrades, which expand how much new generation can be added within a zone; and
2. Transfer upgrades, which increase the amount of power that can move between zones (if transfer upgrades are selected, these changes are also reflected as relaxed transfer limits in the production cost model).

PAC's transmission options are known projects modeled through interconnection studies or ongoing transmission planning processes. Near-term generation resource expansion options are also based on cluster study data, while generic options are available for years beyond the current clusters. This approach enables PAC's IRP model to co-optimize resource and transmission investments by selecting transmission upgrades along with realistic generation additions.

Accounting for the Production Cost Value of New Transmission

PAC also incorporates the production cost value of transmission into their portfolio optimization process using iterative capacity expansion and production cost modeling.[41] After the capacity expansion model selects a resource and transmission portfolio, the production cost model simulates hourly dispatch and identifies congestion on the transmission system. These congestion values are

[40] PAC 2025 IRP, Public Input Meeting (Sept. 25, 2024), "Transmission Options," slides 56-60.
[41] PAC 2025 IRP, "Granularity Adjustment Detail," pp. 185-186.

then fed back into the capacity expansion model as credits, reducing the modeled cost of transmission upgrades that alleviate congestion and lower fuel costs. This iterative process continues until the resource and transmission selection stabilizes. By quantifying the production cost value of expanded transmission and incorporating those benefits into investment decisions, PAC's IRP model selects upgrades that unlock access to lower-cost energy.

Transparency is Paramount

While PAC's approach to incorporating transmission options in IRP modeling is a leading regional example, they do not specify how they decide which transmission projects to include. Furthermore, assessing transmission options in IRP modeling is only successful if utilities follow through with projects identified as part of the least-cost plan. With PAC's last-minute removal of the Boardman to Hemingway transmission line in the 2025 IRP, it is difficult to assess their overall success.

2.5. Transmission Planning Studies

In our Part 1 report, we recommend that utilities coordinate transmission planning studies with their IRP to: 1) define more accurate model inputs—including zonal interconnection capacity, transfer limits, and transmission upgrade options—and 2) re-examine the transmission upgrades required to deliver portfolios considered in the final stages of analysis. Several IRPs include studies that address one of these two steps. The rubric in this section assesses the extent to which transmission planning studies directly inform transmission options considered in each IRP. This rubric simplifies a complex process, particularly given variation in how utilities incorporate IRP results into procurement. However, procurement is beyond the scope of our analysis in this report. We focus here on how well transmission planning studies are coordinated with IRP modeling to ensure realistic expansion options are evaluated during IRP portfolio development and selection.

Table 8. Transmission Planning Studies

Studies used to re-examine IRP model results
Studies directly inform transmission options
Studies inform IRP model constraints
No transmission planning studies

Utility	Studies Inform Transmission Expansion Options	Studies Used to Re-examine IRP Portfolio Results	Relevant Transmission Planning Studies Identified in the IRP	Approach
SRP	No	Yes	Transmission Investment Planning Process[42]	
PAC	Yes	No	Transmission Interconnection Options[43]	
PNM	Yes	No	Transmission System Upgrades 20-Year Transmission Planning Outlook[44]	
APS	No	No	None	
NVE	No	No	None	

[42] SRP 2023 ISP, "Transmission Investments," pp. 86-87; "Results - Transmission Investments," pp. 115-117; "Balanced System Plan - Transmission," p. 159.
[43] PAC 2025 IRP, Public Input Meeting (June 2024), "Transmission Interconnection Options," slides 98-105.
[44] PNM 2023 IRP, Transmission System Upgrades, pp. 150-154; PNM, *20-Year Transmission Planning Outlook*, September 2025..

Identifying Transmission Constraints

APS and NVE do not explicitly coordinate transmission planning studies with their IRP. However, like other utilities, their IRP teams work with the transmission planning team to identify transmission constraints used in IRP models. Additionally, APS and NVE's transmission planning teams evaluate transmission options to deliver the IRP portfolio after the IRP is complete. All utilities that include transmission constraints in IRP models must coordinate with transmission planning staff who provide assumptions that inform resource expansion limits and transfer limits. This standard industry practice falls short of the deliberate and explicit coordination of transmission planning studies with the IRP that we recommend and observed in other IRPs.

Transmission Planning Studies Before vs. After IRP Modeling

SRP, PAC, and PNM explicitly coordinate transmission planning studies with IRP modeling, but in different ways. PAC and PNM use studies to define specific potential transmission expansion options in their capacity expansion model. PAC does this by giving their zonal model the option to select transmission upgrades studied through their generator interconnection process.[45] PNM does this using zonal transmission cost adders derived from conceptual transmission projects studied by their transmission planning team[46] (PNM separately conducted a 20-year transmission planning process outside their IRP, which we discuss below). Both utilities use transmission planning studies conducted *before* IRP modeling to define realistic transmission expansion options in their capacity expansion models.

In contrast, SRP's capacity expansion model does not consider transmission expansion options except for two specific options: wind and geothermal resources (using single-resource transmission cost adders). However, SRP conducts a "Transmission Investment" planning process within their IRP that identifies specific transmission upgrades required to deliver three resource portfolios created using different IRP scenarios and generation siting strategies.[47] Transmission cost estimates from these three scenarios are extrapolated to *all* IRP portfolios to inform selection of the preferred plan. SRP's approach uses transmission planning studies to model transmission upgrade options *after* IRP modeling, but in a way that still informs portfolio evaluation and final IRP results. We elaborate on SRP's approach in the case study below.

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[45] PAC 2025 IRP, Public Input Meeting (June 2024), "Transmission Interconnection Options," slides 98-105.
[46] PNM 2023 IRP, Transmission System Upgrades, pp. 150-154.
[47] See *Case Study 3*.

Iterative Transmission Planning Studies

PNM comes close to the approach we recommend: iterative intra-IRP transmission planning studies to inform transmission expansion options (used as model inputs) and to re-examine IRP portfolios (the results of IRP modeling) to ensure accurate transmission upgrades inform selection of a preferred plan. After completing their 2023 IRP, PNM conducted a 20-year transmission planning study to evaluate transmission solutions to deliver their 2023 IRP portfolio and address other system needs.[48] PNM has indicated that the results of this study will inform transmission options included in their next IRP. PNM's approach to proactive transmission expansion planning between IRP cycles accomplishes the type of iteration we believe is best practice, although over a more extended period. We hope that future IRPs (PNM's and others) will coordinate transmission planning more closely with the IRP analysis so that transmission studies inform portfolio evaluation rather than occurring only after the IRP is complete.

Using the IRP to Inform Transmission Planning

This report focuses on how to incorporate transmission in IRPs, but it is essential that utilities also use IRP results to inform their transmission planning. SRP's analysis of resource location scenarios (discussed in the case study below) is a good example. This modeling identifies transmission upgrades that are sound investments despite uncertain future conditions, while informing future resource siting decisions to optimize use of the existing transmission grid.[49]

Transparency

Throughout this report, we argue that utilities should consider transmission upgrades in the IRP. Transparency in how the utilities identify the candidate transmission expansion options is essential to ensuring that appropriate upgrades are evaluated accurately. However, none of the IRPs we evaluated provide this transparency. More broadly, all utilities should establish clear procedures for coordinating interconnection requests and other transmission planning work with their IRP analyses, and explain their procedures for coordination to their regulators and stakeholders. Utilities should also include all relevant transmission projects in IRPs for fulsome consideration. Failing to consider certain relevant projects—like PacifiCorp does in its 2025 IRP—makes it difficult to have confidence in the results because relevant comparisons are necessarily absent.

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[48] PNM, *20-Year Transmission Planning Outlook*, 2025.
[49] See *Case Study 3*.

Recommendations:

- APS, NVE, and SRP should use transmission planning studies to define transmission expansion options in their capacity expansion models.
- All utilities should use transmission planning studies to re-examine the transmission upgrades required to deliver portfolios considered in the final stages of analysis.
- All utilities should establish and publish transparent procedures for coordinating transmission and resource planning.

Case Study 3: Salt River Project's Analysis of Resource Location Scenarios

In SRP's 2023 IRP, they use power flow modeling of the 2035 system to identify transmission investments required to maintain reliability under three different IRP cases and two resource location sensitivities:[50]

- **Pro-Rata**: Siting of new resources is assumed to follow historical interconnection patterns.
- **Hub**: Siting of new gas, solar, and storage are assumed to be concentrated at a proactively-planned 500 kV switchyard southeast of Phoenix.

Key findings:

- Resource locations significantly change the transmission investments needed.
- A Pro-Rata approach requires SRP to build less new high-voltage transmission than a Hub in all scenarios except when coal is limited (because higher solar and battery additions further exceed the existing transmission system capacity).
- Major transmission investment is necessary over the next decade in all scenarios, and proactive planning is essential to account for long development times.

SRP's preferred system plan proposes a hybrid siting strategy: continue Pro-Rata siting but avoid adding new generation resources in areas that trigger major transmission upgrades. This transmission planning study also identifies transmission upgrades that are sound investments in multiple scenarios, giving the utility confidence to pursue these projects despite future uncertainty.

Finally, SRP uses the same transmission study to extrapolate transmission upgrade costs for each IRP portfolio. This ensures that SRP's selection of a preferred plan accounts for transmission costs required to deliver generation resources.

[50] SRP 2023 ISP, "Transmission Investments - Methodology Overview," pp. 86-87; "Results - Transmission Investments," pp. 115-117; "Balanced System Plan - Transmission," p. 159.

3. Ranking and Utility-Specific Recommendations

Utilities in the Interior West vary widely in how effectively they evaluate transmission opportunities in their IRPs. Some incorporate transmission in IRP modeling fairly comprehensively, while others omit transmission considerations entirely. The table below ranks each utility based on the five methods we observed in recent IRPs, with colors indicating the depth of transmission integration—green representing best practices, and red indicating that transmission was omitted.[51]

Table 9: Which recent IRPs best evaluate transmission expansion opportunities?

Observed Methods for Evaluating Transmission Opportunities in IRPs

Rank	Utility & IRP	Resource Expansion Limits	Transfer Limits	Transmission Scenarios	Transmission Expansion Options	Transmission Planning Studies
1	PAC 2025 IRP					
2	PNM 2023 IRP					
3	SRP 2023 ISP					
4	NVE 2024 IRP					
5	APS 2023 IRP					

Utility-Specific Recommendations

The report cards below summarize our assessment of each IRP and provide utility-specific recommendations. We hope that utilities and regulatory staff will take these suggestions as a starting point for discussing how each utility can better evaluate transmission expansion opportunities in their next IRP.

[51] These rankings assess how effectively each utility's latest IRP evaluates transmission expansion opportunities. The rankings do not consider prior IRPs nor do they incorporate non-transmission-related IRP methodologies broadly or other issues outside the scope of transmission. Additionally, this analysis focuses on IRPs, which are inherently a planning exercise and may not indicate how effectively utilities put IRP plans into action via subsequent investment decisions and development activities. These topics are important, but outside the scope of this report.

Transmission in IRP Report Card

PacifiCorp (PAC)

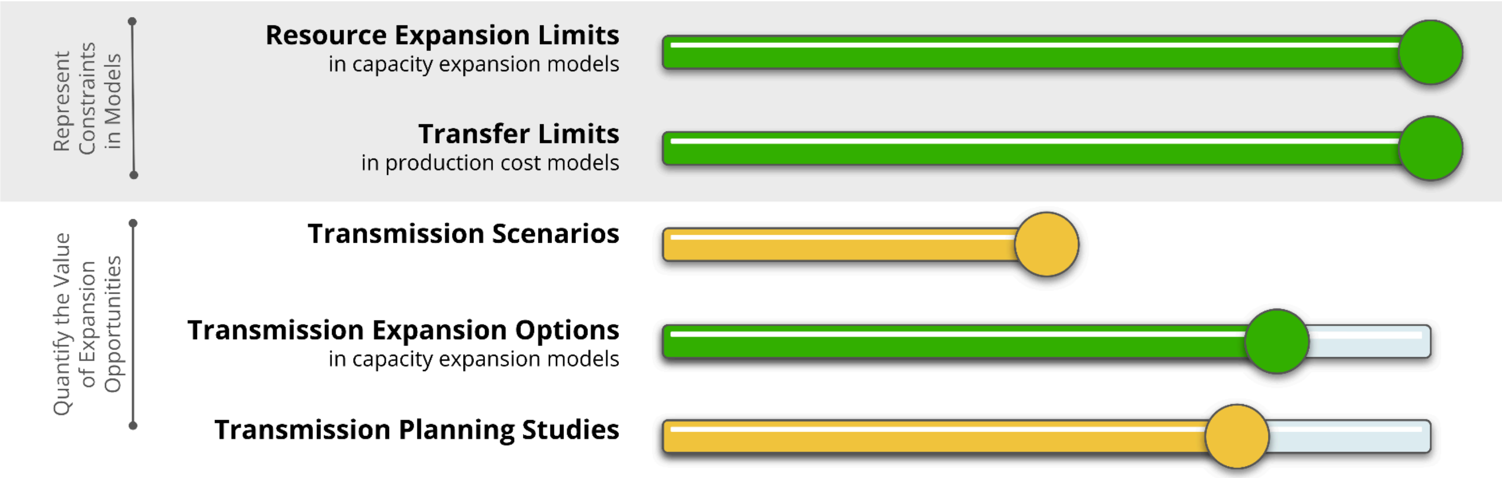
Rank:

1 PAC
2 PNM
3 SRP
4 NVE
5 APS

1 /5

Summary: PAC's model can select transmission upgrades and their use of iterative modeling to account for production cost benefits is laudable. Future IRPs should include regional transmission options, evaluate more scenarios, include analysis of all relevant and planned transmission projects, and improve transparency by explaining how transmission options are selected and defined. PAC's score is relative and could be improved by more robustly analyzing all pertinent transmission projects.

*How did **PAC** evaluate transmission opportunities in their **2025 IRP**?*



Effective Approaches	• Highly granular production cost model. • Capacity expansion model is zonal and can select transmission upgrade options, which are coordinated with PAC transmission planning. • Iterative modeling quantifies production cost value of transmission additions.
Areas for Improvement	• Use more transmission scenarios to evaluate impacts of potential transmission investments (specific projects or portfolios of upgrades). • Include regional transmission options and assess their capacity value. • Increase transparency in how transmission options are selected for inclusion in the IRP.
Show Your Work	• PAC's monthly stakeholder IRP meetings are extensive, but the IRP report should provide more details about transmission analysis.

Public Service Company of New Mexico (PNM)

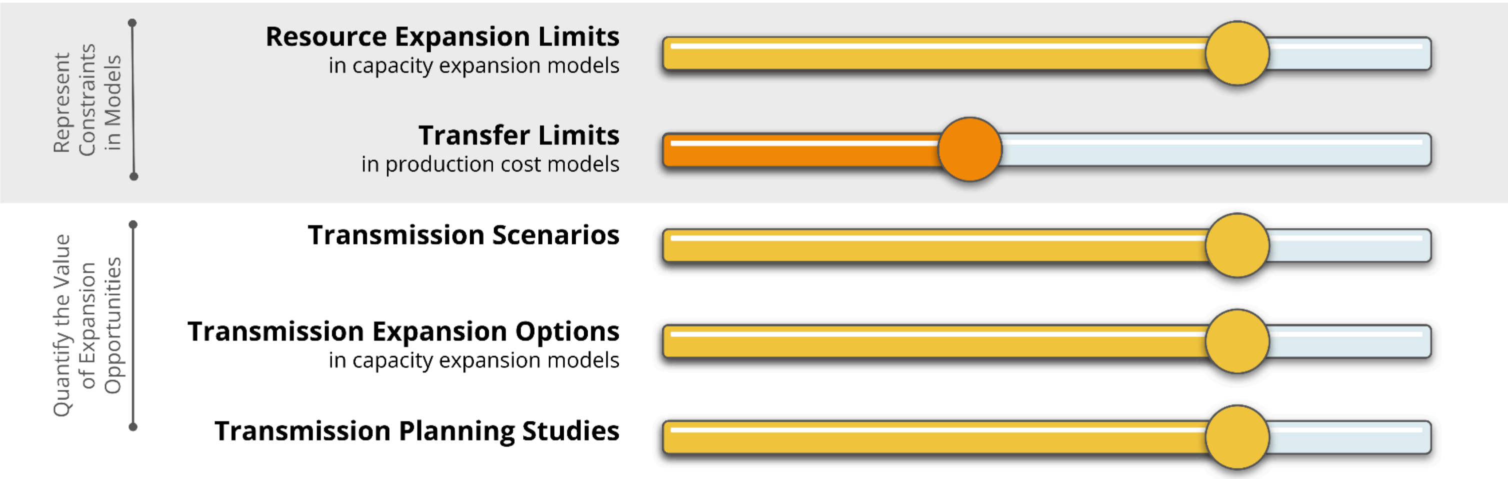
Rank:

1 PAC
2 PNM
3 SRP
4 NVE
5 APS

2 /5

Summary: PNM's zonal production cost model and zonal transmission adders enable their capacity expansion model to select generation additions while accounting for transmission upgrade costs. Future IRPs should quantify the production cost value of new transmission and incorporate transmission costs in the evaluation of IRP portfolios. This may require additional intra-IRP transmission studies and use of a zonal capacity expansion model with transmission upgrade options.

*How did **PNM** evaluate transmission opportunities in their **2023 IRP**?*



Effective Approaches

- Multiple load and resource zones are used in the production cost model.
- Transmission expansion options include specific conceptual upgrades studied by the transmission planning team.
- Early wind scenario quantifies benefits of expedited transmission.

Areas for Improvement

- Quantify the production cost value of new transmission by increasing transfer limits if the model selects resources with transmission adders.
- Include additional scenarios with transmission variation to quantify portfolio impacts of transmission upgrades.
- Coordinate transmission studies with IRP modeling to re-examine portfolios considered when selecting a preferred plan.

Show Your Work

- PNM's IRP report is clear and utility staff responded to our questions.

Salt River Project (SRP)

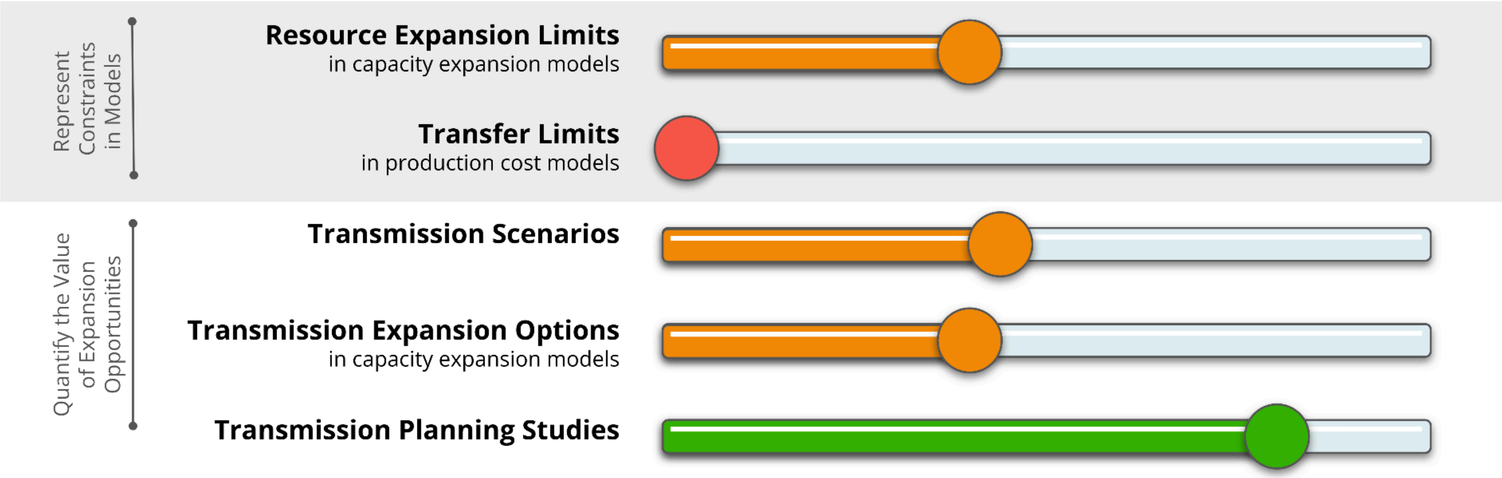
Rank:

1 PAC
2 PNM
3 SRP
4 NVE
5 APS

3 /5

Summary: SRP used transmission planning studies in their IRP to assess the cost of transmission upgrades when selecting a preferred portfolio. The next IRP should assign resource expansion limits comprehensively by zone and include zones with transfer limits in the production cost model. Once the models represent transmission constraints, SRP should include additional transmission expansion options in the capacity expansion model and additional scenarios with specific transmission changes.

*How did **SRP** evaluate transmission opportunities in their **2023 IRP**?*



Effective Approaches	•	Targeted transmission planning studies for three generation portfolios enabled cost estimates for additional portfolios and informed both transmission planning and selection of preferred generation portfolio.
	•	Transmission cost adders differentiated remote wind and geothermal options with clear explanations.
Areas for Improvement	•	Add zones with transfer limits in the production cost model.
	•	Apply resource expansion limits and transmission cost adders to all resource options by zone.
	•	Include scenarios with specific transmission changes.
Show Your Work	•	SRP's IRP report is clear and accessible, and planning staff made time to meet and answer our questions.

NV Energy (NVE)

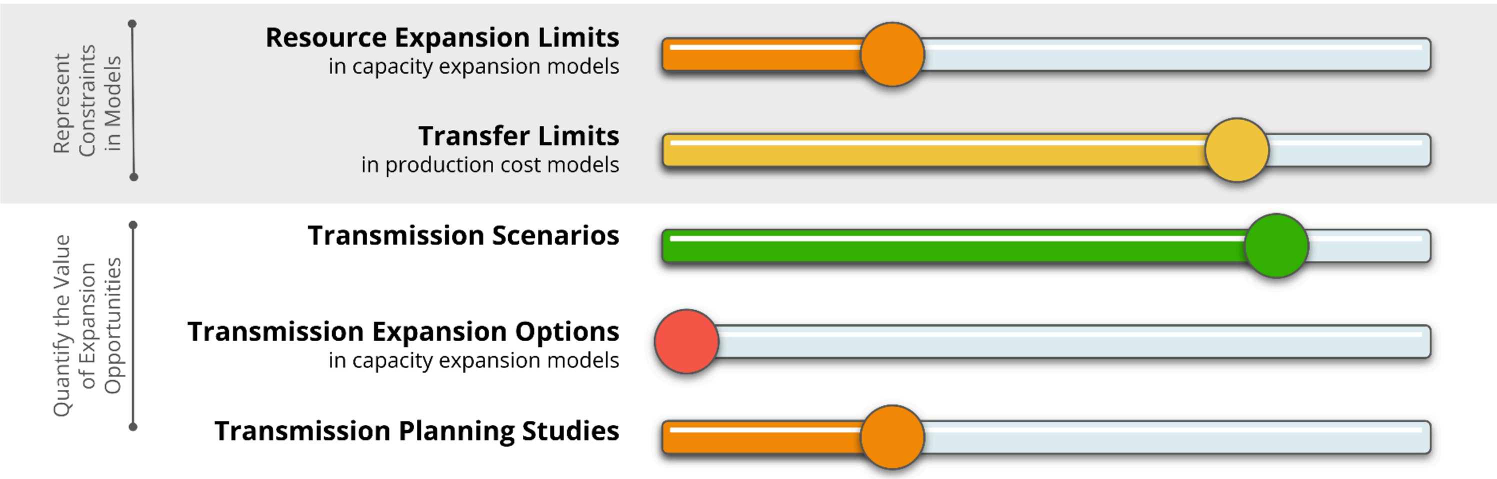
Rank:

1 PAC
2 PNM
3 SRP
4 NVE
5 APS

4 /5

Summary: NVE's production cost model includes zones and transmission constraints, and NVE used one scenario to analyze the value of the planned Greenlink transmission upgrades. Future IRPs should include transmission constraints and new expansion options in the capacity expansion model and use scenarios to quantify the value of other (non-planned) transmission opportunities.

*How did **NVE** evaluate transmission opportunities in their **2024 IRP**?*



Effective Approaches	• NVE's zonal production cost model captures transmission constraints between important load and resource zones. • "No Greenlink" scenario quantifies multiple transmission benefits.
Areas for Improvement	• Add resource expansion limits and cost adders in each zone to reflect transmission constraints and upgrade options. • Use scenarios, transmission expansion options, and transmission planning studies to evaluate additional transmission upgrades (beyond Greenlink).
Show Your Work	• Utility staff answered questions. However, NVE should create opportunities for stakeholder engagement and discussion of the IRP, similar to other utilities in the region.

Arizona Public Service (APS)

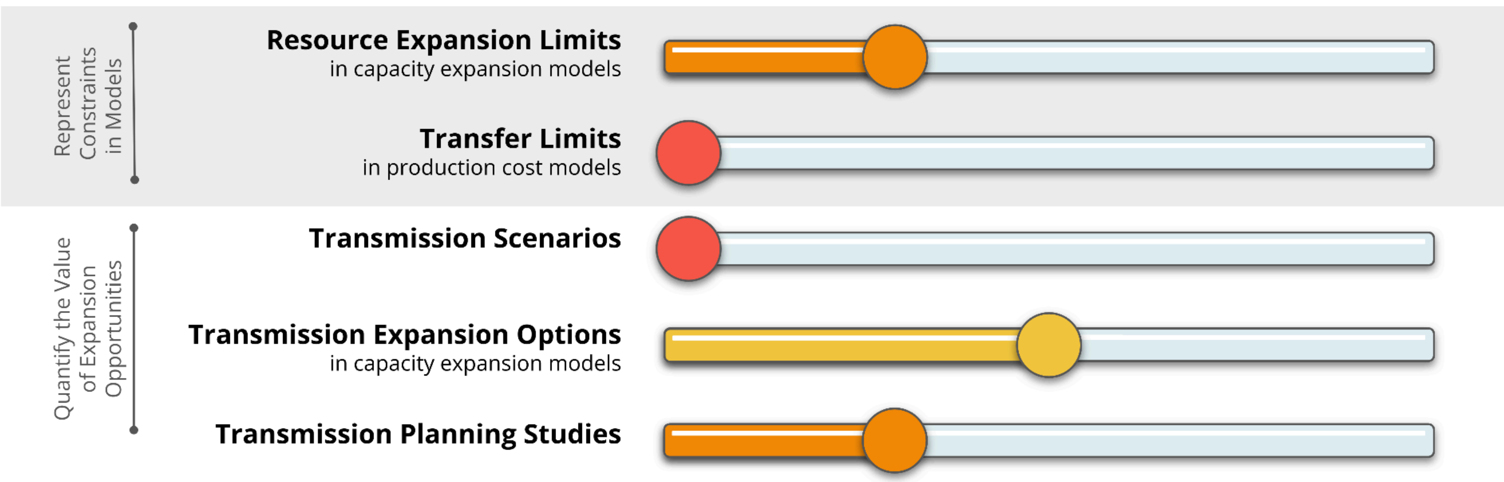
Rank:

1 PAC
2 PNM
3 SRP
4 NVE
5 APS

5 /5

Summary: APS's IRP mostly omitted transmission constraints. The next IRP should transparently explain APS's transmission analysis and modeling decisions, which should include representing all known and anticipated transmission constraints using additional resource expansion limits as well as zones with transfer limits in the production cost model. APS's next IRP should quantify the value of transmission upgrades using scenarios or transmission expansion options.

*How did **APS** evaluate transmission opportunities in their **2023 IRP**?*



Effective Approaches	• Transmission cost adders account for transmission upgrade costs for all resources, with specific expansion costs and limits for NM wind.
Areas for Improvement	• Define multiple zones in the capacity expansion model to differentiate resource expansion limits and transmission expansion options. • Add zones with transfer limits in the production cost model to represent anticipated transmission constraints on APS's system. • Use scenarios to evaluate the portfolio benefits of alternative transmission expansion options. • Coordinate transmission studies with the IRP to inform more detailed transmission costs and expansion options.
Show Your Work	• Staff made time to explain modeling, but the IRP doesn't clearly explain how APS considered transmission constraints and opportunities.

References

Integrated Resource Plans

Utility	IRP
APS	Arizona Public Service. (2023, November). *2023 Integrated Resource Plan* (Docket No. E-99999A-22-0046). Arizona Corporation Commission. https://edocket.azcc.gov/search/docket-search/item-detail/26260 Also available at the time of publishing at https://www.aps.com/en/About/Our-Company/Doing-Business-with-Us/Resource-Planning
NVE	NV Energy. (2024, May). *2024 Integrated Resource Plan* (Docket No. 24-05041). Public Utilities Commission of Nevada. https://puc.nv.gov/Dockets/ Also available at the time of publishing at https://www.nvenergy.com/about-nvenergy/rates-regulatory/recent-regulatory-filings
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