Stakeholder Meeting (Q4 2020)

Exploring Western Organized Market Configurations: A Western States' Study of Coordinated Market Options to Advance State Energy Policies (or the "State-Led Market Study")

Webinar (via Fall 2020 Joint CREPC-WIRAB Webinar Series)
October 30, 2020
11:00 am – 12:30 pm Mountain Time

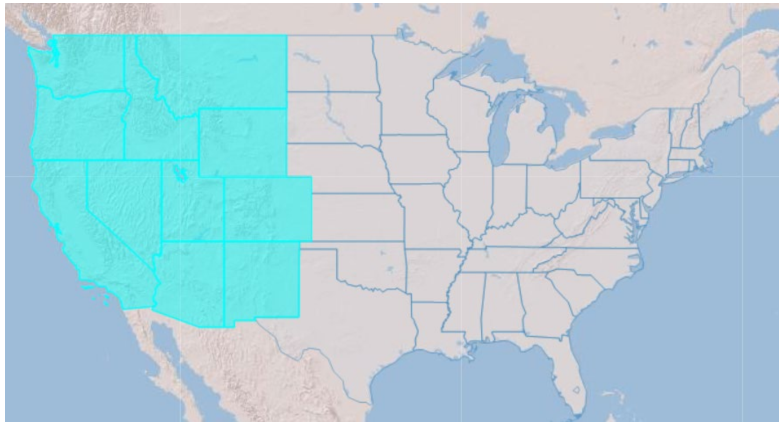
Agenda

1. **Introduction – *Utah Office of Energy Development***
2. **Project Overview and Progress to Date – *Energy Strategies***
   - ❖ Project Timeline & Status Update
   - ❖ Stakeholder Engagement Plan Reminder
3. **Technical Work Plan – *Energy Strategies***
   - ❖ Quick recap of study scope
   - ❖ Results from 2020 studies
   - ❖ Status of 2030 studies
4. **Market and Regulatory Review Work Plan – *Energy Strategies***
5. **Observations from Lead Team Members**
6. **Public Comment and Discussion**

State-Led Market Study made possible through DOE grant

- **The last several years have featured numerous discussions and initiatives related to the formation of coordinated wholesale trading markets in the West**
- **The Utah Governor's Office of Energy Development, in partnership with State Energy Offices of Idaho, Colorado, and Montana, applied for and received a grant from the US DOE to facilitate a 2-year state-led assessment of organized market options**
- **The project is called *Exploring Western Organized Market Configurations: A Western States' Study of Coordinated Market Options to Advance State Energy Policies***
  - ❖ Or "State-Led Market Study"
- **The project provides Western States with a neutral forum, and neutral analysis, to independently and jointly evaluate the options and impacts associated with new or more centralized wholesale energy markets and potential footprints**
- **Today is the fourth quarterly stakeholder meeting for the project**
  - ❖ Timing of next meeting is TBD but will be communicated via Stakeholder distribution list for this project – likely to be late Q4

State representatives from 11 Western States are participating in project



Lead Team

- **Representatives on Lead Team represent interest of their respective states but take all stakeholder input into consideration**
- **Work coordinated primarily through monthly calls**
- **Group seeks decisions by consensus**
    - ❖ Formal votes are an option, if necessary (but have not been used)

Lead Team	Name	Organization
AZ Lead	Steve Olea	Arizona Corporation Commission
	Bob Burns	Arizona Corporation Commission
CA Lead	Grace Anderson	California Energy Commission
	Yulia Schmidt	California Public Utilities Commission
CO Lead	Erin O'Neill	Colorado Public Utilities Commission
	Keith Hay	Colorado State Energy Office
ID Lead	John Chatburn	Idaho Governor's Office of Energy and Mineral Resources
MT Lead	Jeff Blend	Montana Energy Office, Montana Department of Environmental Quality
	Ben Brouwer	Montana Energy Office, Montana Department of Environmental Quality

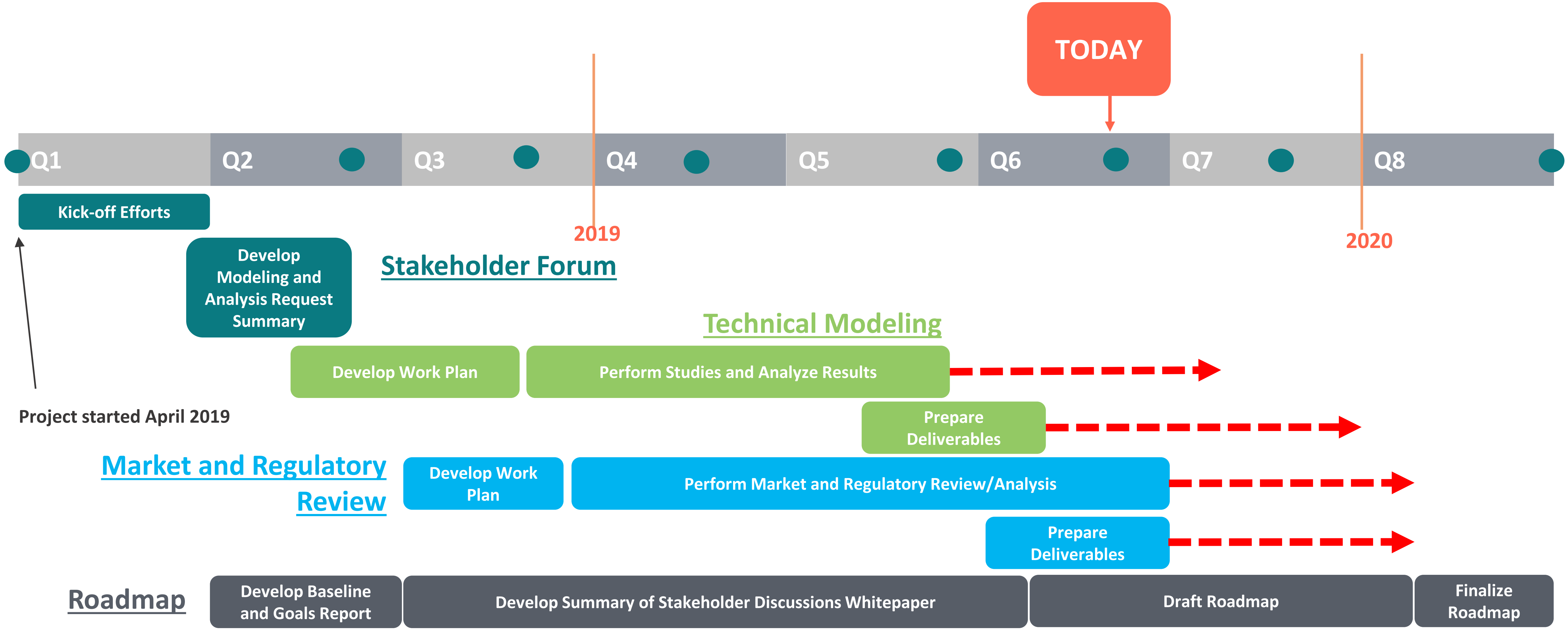
Lead Team	Name	Organization
NM Lead	Mark Gaiser	New Mexico Energy, Minerals and Natural Resources Department
	AnnaLinden Weller	New Mexico Energy, Minerals and Natural Resources Department
NV Lead	Hayley Williamson	Nevada Public Utilities Commission
	David Bobzien	Nevada State Energy Office
OR Lead	Kristen Sheeran	Oregon Energy and Climate Change Policy Advisory to Governor Kate Brown
	Letha Tawney	Oregon Public Utilities Commission
UT Lead	Chris Parker	Utah Department of Public Utilities
	Brooke Tucker	Utah Governor's Office of Energy Development
WA Lead	Steve Johnson	Washington Utilities and Transportation Commission
	Glenn Blackmon	Washington State Energy Office at the Department of Commerce
WY Lead	Kara Fornstrom	Wyoming Public Service Commission
	Bryce Freeman	Wyoming Office of Consumer Advocate

Project Overview and Progress to Date

Energy Strategies

Summary of project timeline

- Two-year timeline (eight quarters), but project may take less time to complete or may take more (deadline extension from DOE is in process to provide flexibility given remote work challenges)
- Stakeholder Forum continues for project duration
- Key deliverables from each work area; body of work feeds into Roadmap



Recap: May Stakeholder Meeting and Feedback

- **Held May 1, 2020 via webinar**
- **Focused on changes to Technical Work Plan based on prior stakeholder feedback**
- **Update on study status and review of methods**
- **Solicitation of feedback from stakeholders**

May 1, 2020 Stakeholder Meeting Agenda

Agenda

1. **Introductions - *All***
2. **Project Overview and Progress to Date – *Energy Strategies***
   a) Project Timeline & Status Update
   b) Stakeholder Engagement Plan Reminder
3. **High-Level Review of Technical Work Plan**
4. **Review of Stakeholder Feedback and Lead Team Responses (including Changes to the Technical Work Plan)**
   a) Market Footprints
   b) Capacity Benefits for Various Market Constructs
5. **Updated Workplan Addressing Capacity Benefits**
6. **Public Comment**
7. **Next steps and future meetings – *Utah Office of Energy Development***

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Project Status Update

- ✓ **The Modeling and Analysis Request and Guidance Summary is complete:**
  - ✓ Discussed during the October 2019 stakeholder meeting
  - ✓ ***<u>Highlights key technical questions posed by the Lead Team that the project will seek to address</u>***
- ✓ **Technical Work Plan**
  - ✓ Approved by Lead Team (but open to revisions)
  - ✓ Presented to stakeholders in January 2020 meeting with revisions presented at May 2020 meeting
- ❑ **Technical Modeling efforts are ongoing**
  - ✓ 2020 case build and studies complete
  - ❖ 2030 case build ongoing
- ✓ **Market & Regulatory Analysis Work Plan**
  - ❖ Approved by Lead Team in October 2020
- ❑ **Market & Regulatory Review underway**
  - ❖ Market Factor Scorecard, regulatory approvals, impacts of market constructs on State regulatory authority
- ❑ **Preparation of deliverables is ongoing**

Review of Stakeholder Engagement Plan

- **Objective for today's meeting**
  - ❖ Update stakeholders on study results and ongoing work
  - ❖ Take verbal feedback from stakeholders
  - ❖ Invite the opportunity to provide written comments
    - ➢ Written comments can be submitted to kfraser@energystrat.com through November 13th
    - ➢ Note that we will review comments, but will not respond specifically to each comment received

- **To receive updates and future meeting announcements, navigate to this link to add your name to the project's stakeholder distribution list: http://bit.ly/2nBP6Gt**

- **When possible, we will distribute meeting materials in advance via this distribution list**

Technical Work Plan:
Recap, 2020 Results, 2030 Update

Energy Strategies

Recap: Study is focused on analyzing impacts of three "market constructs"

EIM/Real-Time Market

- ✓ Centrally optimized real-time dispatch – *Day-ahead unit commitment not optimized across market participants*
- ✓ Individual transmission tariffs
- ✓ Limited transmission dedicated to real-time market
- ✓ Balancing Authority Area (BAA) boundaries and associated reliability obligations retained
- ✓ Transmission providers retain operational control of transmission

Day-Ahead Market (DAM)

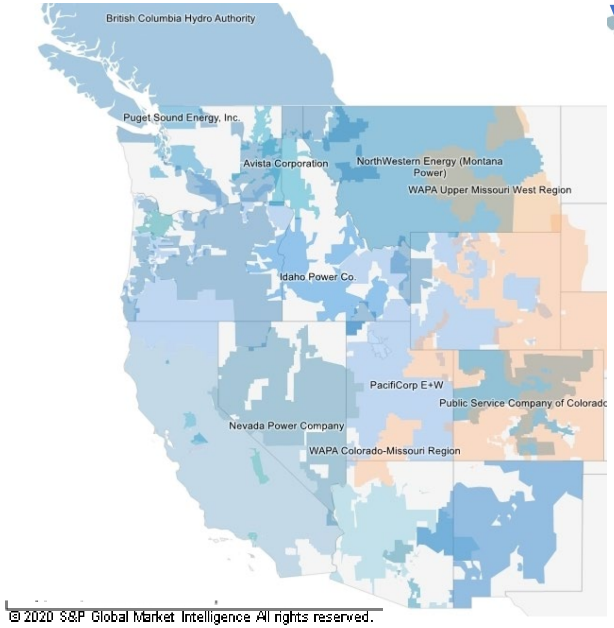
- ✓ Centrally optimized real-time and day-ahead energy market
- ✓ Individual transmission tariffs
- ✓ Limited transmission dedicated to market (other transactions must explicitly pay for transmission)
- ✓ BAA boundaries and associated reliability obligations retained
- ✓ Transmission providers retain operational control of transmission

RTO

- ✓ Centrally optimized real-time and day-ahead energy market
- ✓ Joint transmission tariff for participants in a given footprint
- ✓ Transmission used up to reliability limit
- ✓ BAA boundaries and reliability obligations consolidated
- ✓ Joint transmission planning and cost allocation
- ✓ Transmission providers transfer operational control of transmission

Recap: Market Constructs + Footprints = “Market Configurations”

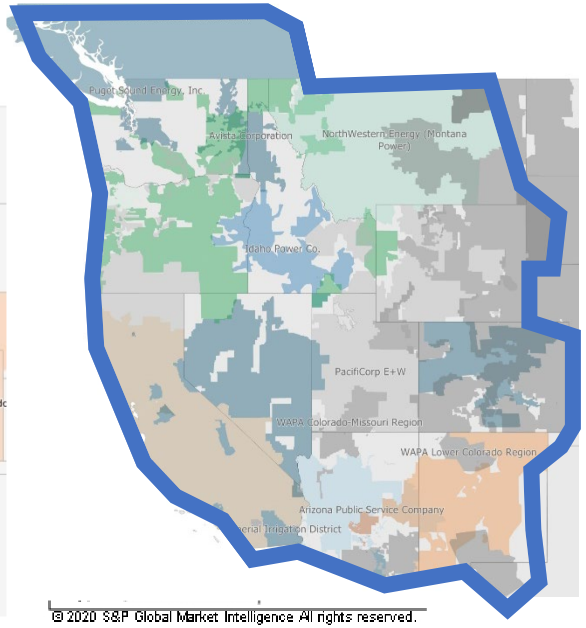
Status Quo



EIM entities that have announced intent to sign EIM Implementation Agreement (or equivalent)*

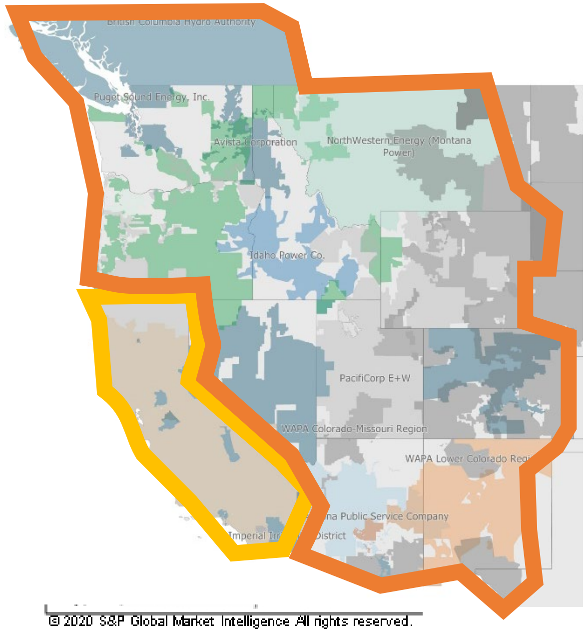
*Announcements that were made before the end of 2019 are included in the Status Quo footprint.

One Market



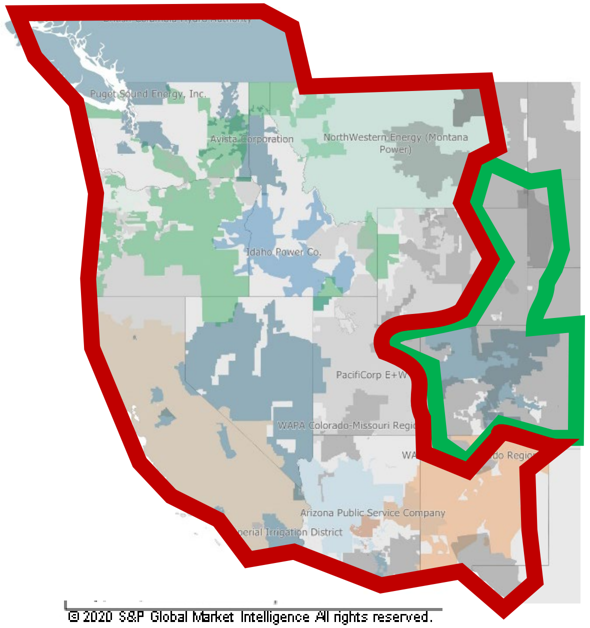
Studied in 2020 and 2030 timeframe

Two Market A



Only studied in 2030 timeframe

Two Market B



Only studied in 2030 timeframe**

**As discussed later in the presentation, the timeframe for studying this market footprint has been adjusted based on stakeholder feedback

Recap: Market Configurations Studied in 2020 and 2030

Study Year	Type	Market Scenario	Market Footprints: Status Quo	Market Footprints: One Market	Market Footprints: Two Market A (No CA Expansion)	Market Footprints: Two Market B (Mountain West & CA Expansion)
2020	Core Studies	Real-time only	✓	✓		
2020	Core Studies	Day-ahead				
2020	Core Studies	RTO		✓		
2030	Core Studies	Real-time only	✓			
2030	Core Studies	Day-ahead	✓	✓	✓	
2030	Core Studies	RTO		✓	✓	✓
2030	Sensitivities	Real-time only (EIM)	A			
2030	Sensitivities	Day-ahead				
2030	Sensitivities	RTO		A & B	B	A & B

Key

Benchmark

Sensitivity Key

A - Major Transmission Build
B - Carbon Price
C - TBD

Work plan was designed to address specific list of questions posed by Lead Team

Recap: Study considers certain market benefits and costs in unique state-level analysis

Market benefits and costs:

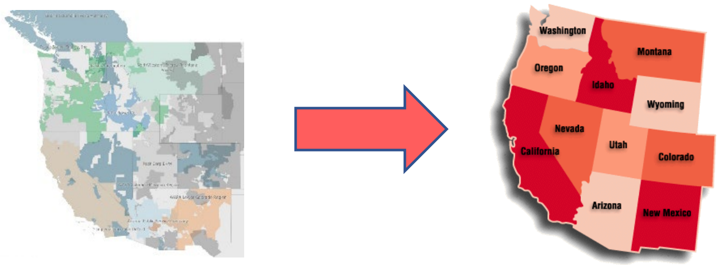
Estimated in study

- ✓ **Production cost savings, which capture:**
  - More efficient trade due to reduced transmission wheeling
  - Optimized unit commitment and dispatch
  - Reduced operating and flexibility reserves
  - Reduced curtailment
- ✓ **Capacity savings**
  - Reduced capital investment due to load diversity
- ✓ **Market start-up/administrative costs**

Not estimated in study

- × **Other market efficiencies: transparency, independence, transmission planning savings**
- × **Policy-driven resource procurement savings**
- × **Reliability benefits**
- × **Transmission cost allocation**
- × **Many unquantifiable factors**

Balancing area-level benefits/costs are estimated then allocated to each applicable state



Other results incorporated into market analysis:

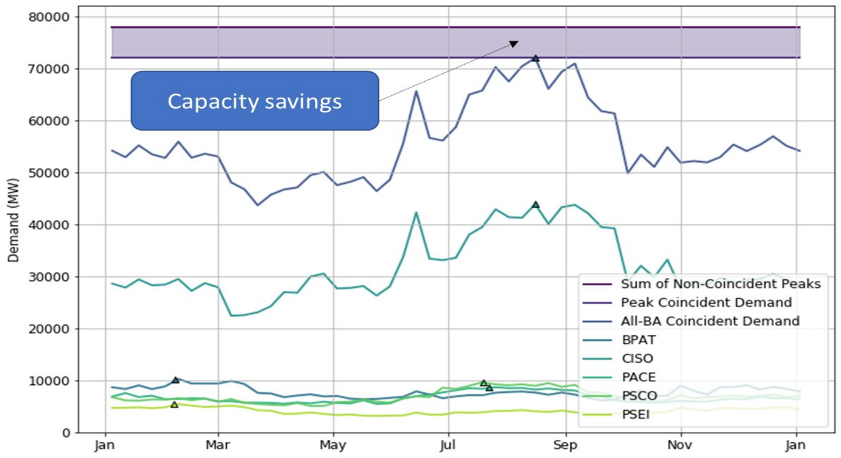
- ❖ Generation dispatch, by type and state (and WECC-wide)
- ❖ Congestion and utilization of transmission paths
- ❖ GHG emissions by state

Capacity Savings

Summary of Methods and Results for 2020 Study Years

Detailed Discussion of Methodology During May Stakeholder Meeting

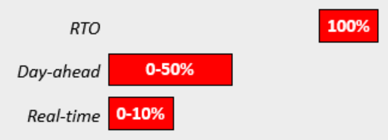
Historical Peak Demand (MW) for BAs in a Conceptual Market Footprint



Method will estimate a range of achievable benefits for each market construct

- Assumes that in **RTO scenarios, 100% of calculated load diversity benefits** can be realized
  - ➢ RTO provides structure to capture full benefit of load diversity
- Assumes that day-ahead market scenarios result in realized **savings of 0-50%** of calculated load diversity benefit, recognizing:
  - ➢ Day-ahead markets may not achieve any capacity savings and status quo planning requirements may continue;
  - ➢ However, enhanced price discovery, resource pooling, and access to transmission could cause changes to reliability requirements and coordination levels that allow some amount of load diversity benefits to be obtained.
- **Real-time only markets** are unlikely to result in significant capacity savings, therefore we assume they can achieve only **0-10% of load diversity benefits**
  - ➢ Increased access to the markets real-time imports that support reliability may, over time, lead to slight changes in amounts of reserves held

Achievable Benefits as a % of Calculated Load Diversity Savings



Approach is to place reasonable bounds on range of capacity benefits provided by various markets such that stakeholders can draw their own conclusions about what level of benefits is most appropriate.

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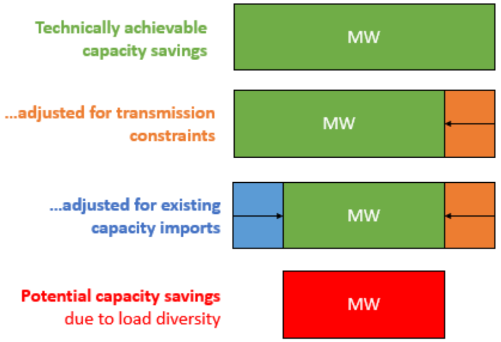
Adjusting Capacity Benefits for Transmission Limits and Existing Coordination

- Method approximates local capacity requirements by taking into account transmission constraints and existing capacity imports
- BA transmission import capabilities
  - ➢ BA import limits determined from WECC path ratings, IRPs, WECC L&R, TTC postings on OASIS, among other sources
- Extent to which BA relies on externally-owned capacity in absence of regional market
  - ➢ Determined through combined effort of reviewing IRPs, leveraging known regional import capabilities, and historical BA interchange data from EIA



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Method requires valuing of capacity savings

- Estimated avoided cost of capacity changes over time in recognition of changes in load-resource balance
- Study year 2020 capacity value estimate assumes no generation investment can be avoided but balancing areas can (or could have) not entered into capacity contracts and/or market purchases
- For the 2030 study year, the estimate assumes the value of capacity in the West will increase as capacity shortages appear and the need to construct avoidable capacity exists.
  - ➢ The value of capacity is assumed to be a net CONE proxy for this scenario
  - ➢ Net CONE: Cost of new entry less revenues from energy and ancillary service markets

Value of Avoided Capacity ($/kW-year)

Year	Capacity Cost	Source
2020	$40/kW-year	Based on 2018 CEC Resource Adequacy Report for 2020 capacity
2030	$110/kW-year	Net CONE proxy value

Hypothetical NGCC CONE	$150/kW-year	CEC - Estimated Cost of New Utility Scale Generation in California: 2018 Update
Estimated Net Revenue	$40/kW-year	CAISO - 2018 DMM Annual Report
Estimated Net CONE	**$110/kW-year**	

Recall that range of achievable savings across market constructs varies and serves as sensitivity to total benefit

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Overview of Methodology

1 Calculate **potential capacity benefit** for each BA in footprint

- BA peak demand compared to its contribution to coincident peak of market footprint
- Capacity savings (MW) determined from hourly demand data

2 **Adjust capacity benefit** for transmission and imports

Methodology considers:
- Maximum import capability of each BA
- Extent to which BA relies on externally-owned capacity in absence of regional market (e.g., existing levels of coordination)

3 **Adjust savings** for market construct and **monetize benefit**

- Various market constructs present a range of savings opportunity requiring adjustments to calculated savings
- Avoided capacity valued changes over time and is unique to study year

4 **Determine capacity savings** across footprint and allocate to states

- Unique results for each study year, market footprint, and market construct
- State-level benefits apportioned based on state's % of BA load

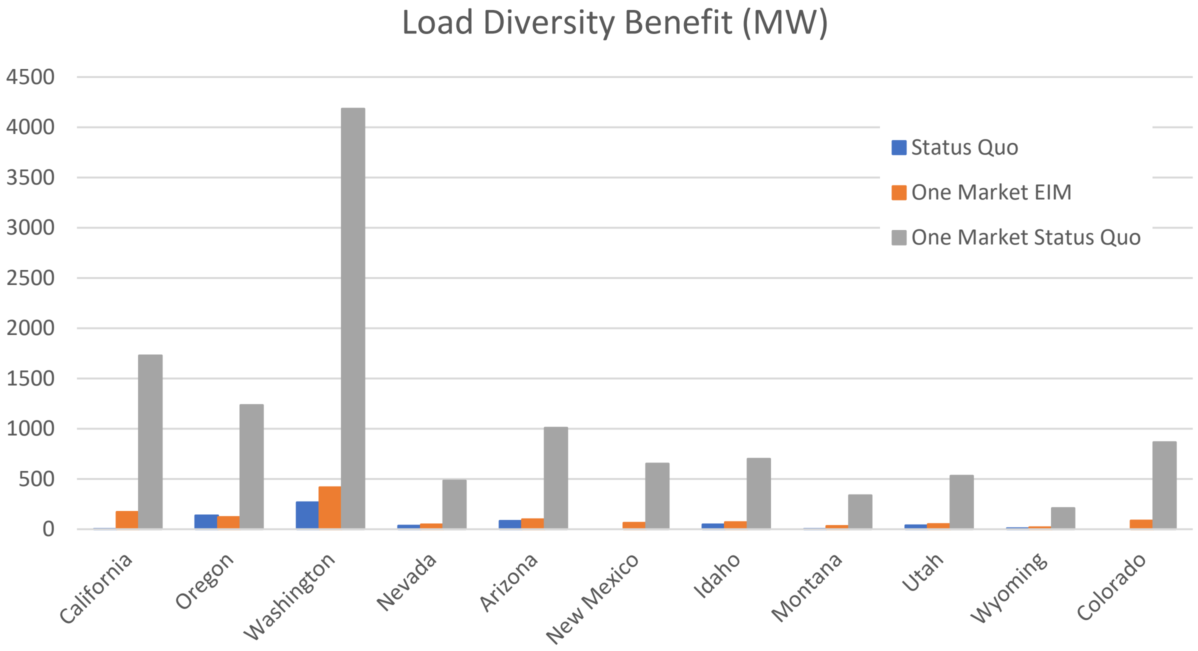
Key data inputs:

- Hourly load data
- Planning reserve margins
- Import capability
- Net CONE and capacity price

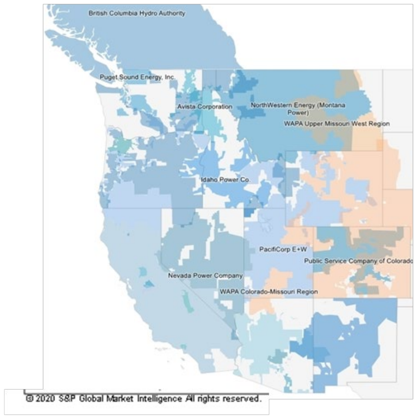
Capacity Benefit Results: 2020

Annual Capacity Saving ($M/year) for Market Footprint

Market Scenario	Market Footprints	
	Status Quo	One Market
Real-Time Only	$0 - $25.2M	$0 - $47.8
RTO	N/A	$478.0



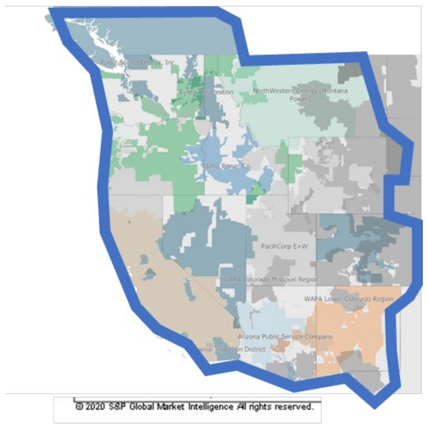
Status Quo



EIM entities that have announced intent to sign EIM Implementation Agreement (or equivalent)*

*Announcements that were made before the end of 2019 are included in the Status Quo footprint.

One Market



Studied in 2020 and 2030 timeframe

- Integration of BAs into a real-time only-market with One Market footprint nearly doubles high-end capacity savings from Status Quo footprint
- Winter-peaking BAs and large load drive capacity savings for Washington
- Capacity savings in Oregon less under One-Market due to reduced load diversity of Oregon BAs compared to market footprint CP in Status Quo

Operational Savings

Results for 2020 Study Year

Overview of Operational Study

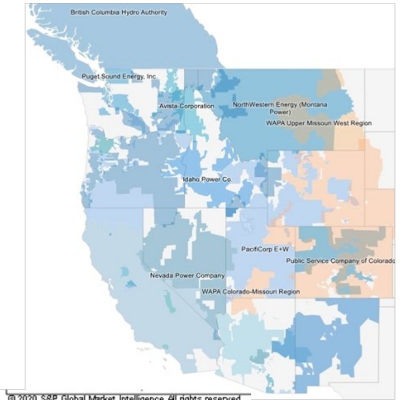
- Study uses production cost modeling to estimate operational savings caused by expanding existing markets and/or adding market constructs
  - ➢ Modeling also used to estimate state-level impacts to generation dispatch, carbon emissions, and transmission flows in region
  - ➢ Production cost modeling studies are most useful when results are analyzed on a *relative* and *directional basis* – these are not precise forecasts of benefits
- Based on final study scope, none of the core questions identified in the Modeling and Analysis Request can be answered through <u>*only*</u> the 2020 studies
  - ➢ Several questions deal with market benefits over time, which will be informed by 2020 studies
  - ➢ 2020 studies are proving ground for market modeling approach and database
- All results in 2018$

2020 Study Cases

Market Construct	Market Footprints	
	Status Quo	One Market
Real-time only	✓	✓
RTO	*N/A*	✓

2020 Market Footprints

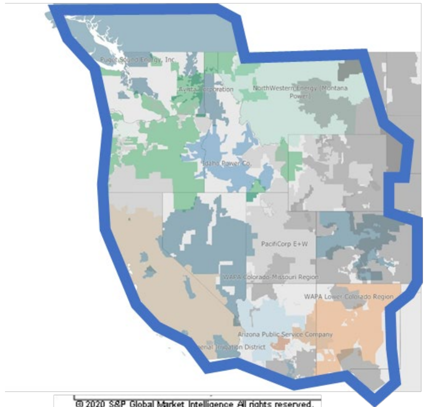
Status Quo



EIM entities that have announced intent to sign EIM Implementation Agreement (or equivalent)*

*Announcements that were made before the end of 2019 are included in the Status Quo footprint.

One Market

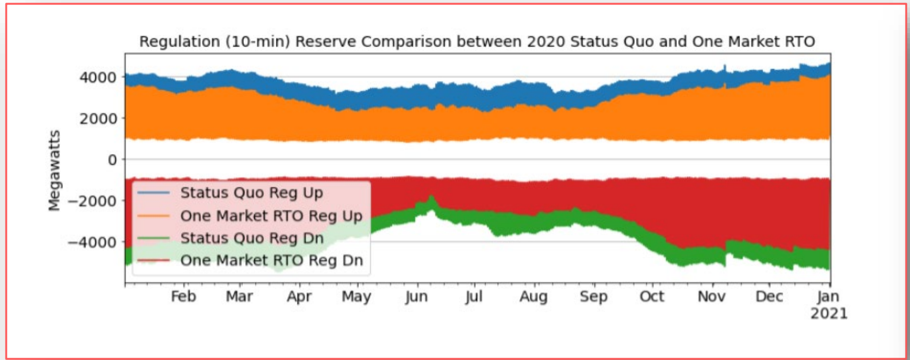


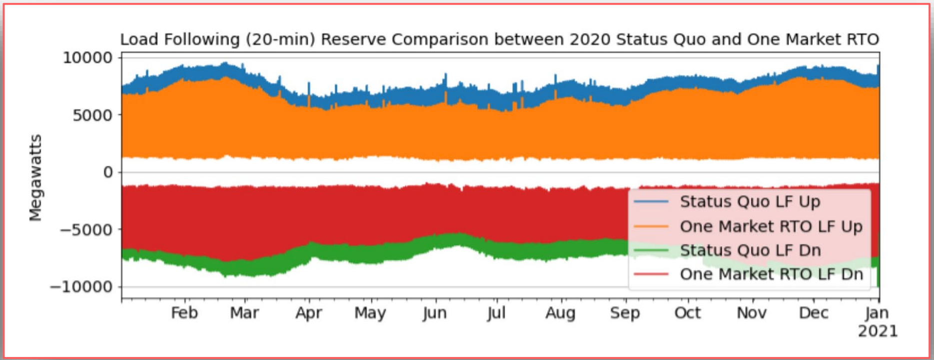
Studied in 2020 and 2030 timeframe

Summary of Market Modeling Assumptions: 2020 Study Year

Assumption	Status Quo	One Market EIM	One Market RTO
Real-time/dispatch trading costs	Removed for EIM participant footprint	Removed for West-wide footprint	
Day-ahead/unit commitment trading costs	Not fully optimized: subject to transmission hurdles between areas		Removed across West-wide footprint
Transmission available for market-driven interchange	Avg. of ~15% of total transfer capability between participants		100% of transfer capability
Cost of transmission in market	No incremental transmission cost for intra-market flows		
CAISO export limit	5,000 MW		None
Operating reserves	BA and reserve sharing groups retained		Single BA
Flexibility reserves	Calculated based on BA demand and variable gen.		Single BA

Generation portfolio, transmission, demand, fuel prices, operational parameters, are all consistent across the three scenarios.

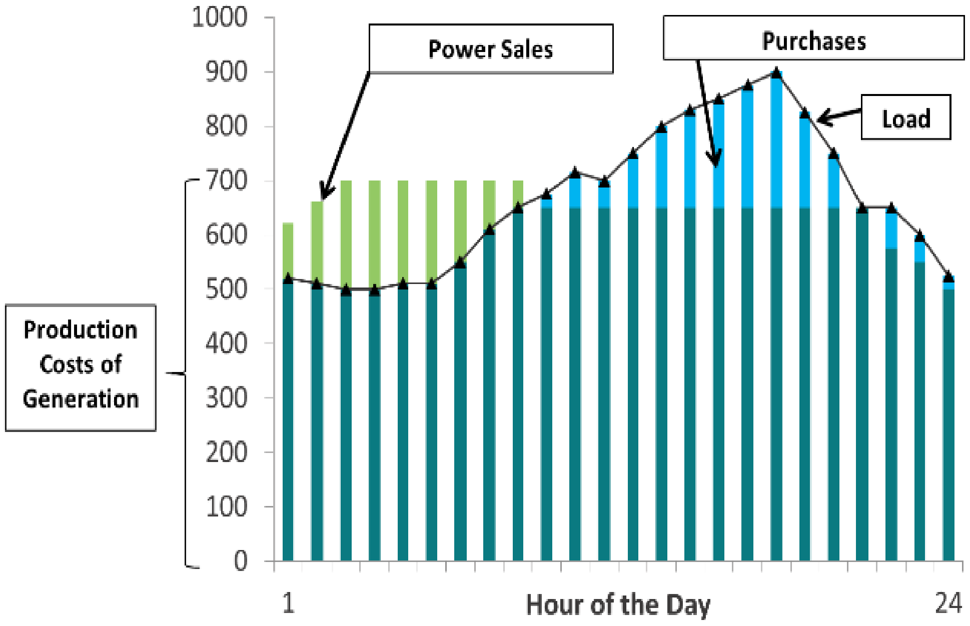


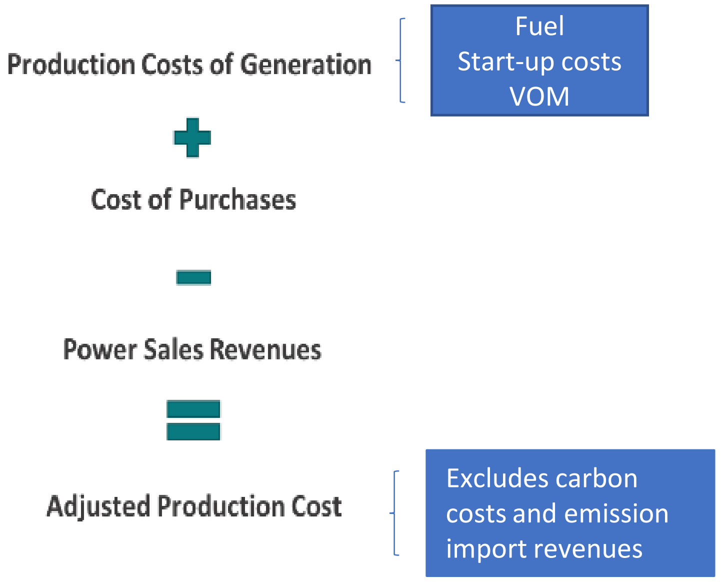


Reminder: Study uses Adjusted Production Cost as Primary Metric to Estimate Operational Savings

- **Adjusted production cost (APC) estimates the net costs for a given area to produce, buy, and sell power**
  - Calculated APC on a balancing authority basis and then allocated APC to each state on a load ratio share basis
- **Automatically corrects and internalizes economic benefit associated with opportunities to export (and increase revenues) or import (and avoid running local generation)**
- **Captures impacts to pricing**

APC Example





2020 Study Results: Western States Overview

2020 Scenario	Western States' Combined APC Savings		Increase in Inter-state Trade		CO_2 Emission Reduction	
	$M	%	$M	%	Short Tons (000s)	%
Benefit of West-wide expansion of real-time only (EIM) market	$105	1%	$238	8%	149	0.1%
Benefit of new West-wide RTO	$811	8%	$1,813	60%	1,543	0.7%

- Changes above are annual values calculated relative to 2020 Status Quo system that represents **current** levels of real-time market participation ($2018)
- Regional trade represents the dollar **sum of total imports and exports** for all Western states (aggregation of balancing areas)
- No material changes to **system curtailments** because Status Quo case had low curtailments

2020 Study Results: Operational Efficiencies

	Fuel Savings	Start-up Cost Savings	Variable O&M Savings		Production Costs Savings
One Market EIM	**$43 million** ↓ 1%	**~$0 million**	**~$0 million**	=	**$42 million** ↓ 0.4%
One Market RTO	**$377 million** ↓ 5%	**$120 million** ↓ 17%	**$72 million** ↓ 3%	=	**$569 million** ↓ 5.5%

- *Changes above are annual values calculated relative to 2020 Status Quo system that represents current levels of real-time market participation ($2018)*
- *Results represent aggregation of Western states*

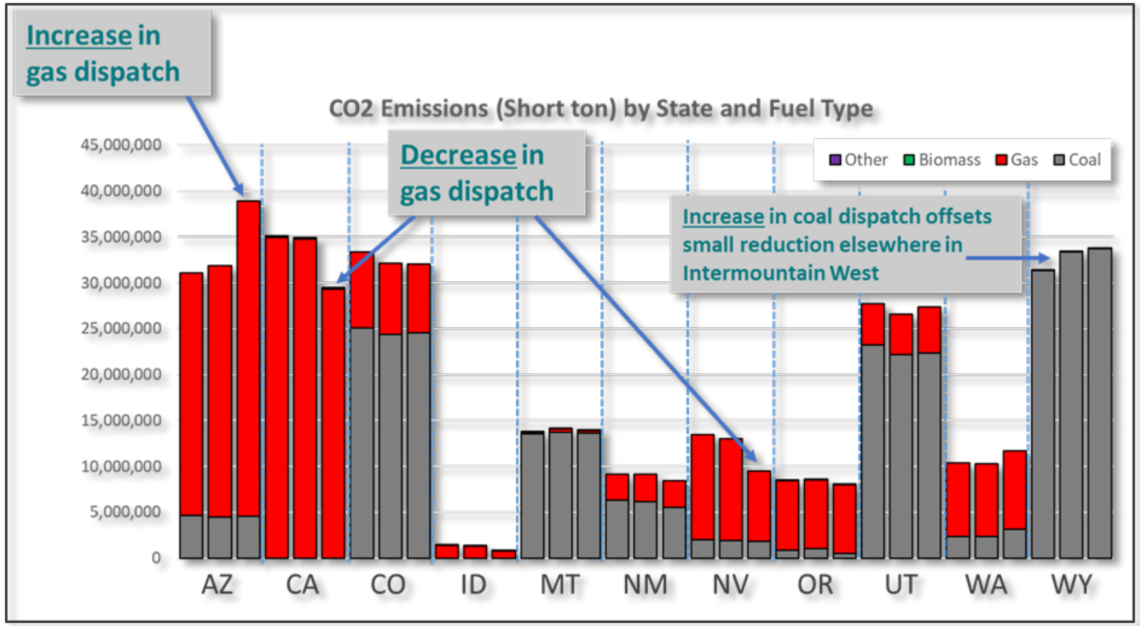
2020 Study Results: Generation Results for Western States

	Coal	Gas	Renewables	CO_2 Emissions
One Market EIM	+282 GWh <1%	-273 GWh <1%	+100 GWh <1%	-149,000 tons 0.1%
One Market RTO	+1,386 GWh 1%	+ 120 GWh <1%	+374 GWh <1%	-1,543,000 tons 0.7%

- *Changes above are annual values calculated relative to 2020 Status Quo system that represents current levels of real-time market participation*
- *Results represent aggregation of Western states*

2020 Study Results: Emissions, Curtailment, and Transmission

- **Total carbon emissions see modest decrease in both market configurations because of more efficient generation dispatch**
  - ❖ Generation is mostly shifting within generation types (not between types)
- **Renewable curtailment is low in all market configurations, with about 0.3% of renewable energy curtailed in the Status Quo case**
  - ❖ Curtailment changes in the two market configuration are minimal
  - ❖ Expect more integration benefits in 2030 studies
- **Transmission flows**
  - ❖ We see shifting of flows across the system generally consistent with new opportunities with economic interchange
  - ❖ New markets don't appear to increase congestion on major paths



				2020 SQ RT EIM		2020 1Mkt RT EIM		2020 1Mkt RTO	
Path	Path Name	Direction	States	U75	U99	U75	U99	U75	U99
P03	P03 Northwest-British Columbia	S→N	WA→BC	0.1%	0.0%	0.1%	0.0%	0.9%	0.0%
P06	P06 West of Hatwai	E→W	ID→WA	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
P08	P08 Montana to Northwest	E→W	MT→ID/WA	3.0%	0.1%	2.0%	0.1%	3.2%	0.1%
P19	P19 Bridger West	E→W	WY→ID	13.9%	1.7%	15.2%	1.2%	11.9%	1.0%
P32	P32 Pavant-Gonder InterMtn-Gonder 230 kV	E→W	UT→NV	0.8%	0.0%	2.2%	0.1%	1.1%	0.1%
P36	P36 TOT 3	N→S	WY/NE→CO	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
P39	P39 TOT 5	W→E	CO	0.0%	0.0%	0.4%	0.0%	2.0%	0.1%
P46	P46 West of Colorado River (WOR)	E→W	NV/AZ→CA	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
P47	P47 Southern New Mexico (NM1)	N→S	AZ→NM	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
P48	P48 Northern New Mexico (NM2)	NW→SE	NM	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
P49	P49 East of Colorado River (EOR)	E→W	AZ→NV/CA	0.0%	0.0%	0.0%	0.0%	2.1%	0.0%
P65	P65 Pacific DC Intertie (PDCI)	N→S	OR/WA→CA	20.2%	2.0%	22.8%	2.0%	29.8%	4.9%
P66	P66 COI	N→S	OR→CA	2.7%	0.0%	2.8%	0.0%	9.9%	0.0%

U75: % of year flow across path meets or exceeds 75% of the path's transfer limit

U99: % of year flow across path meets or exceeds 99% of the path's transfer limit

Increases in…

AZ Exports, CA/NV Imp

NW Exports, CA Imports

Combined Benefits and Observations

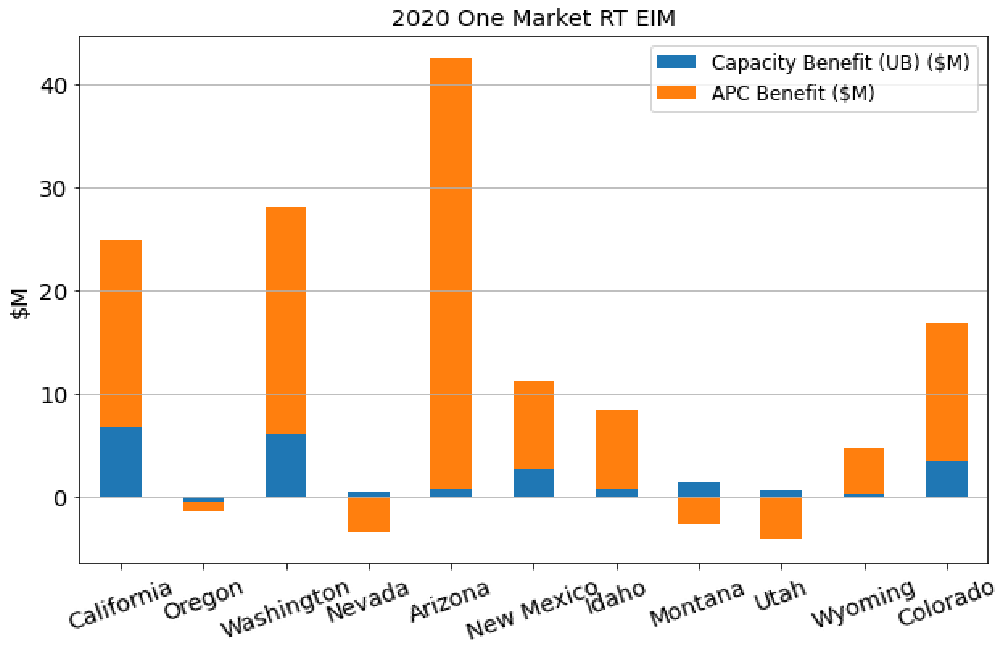
For 2020 Study Year

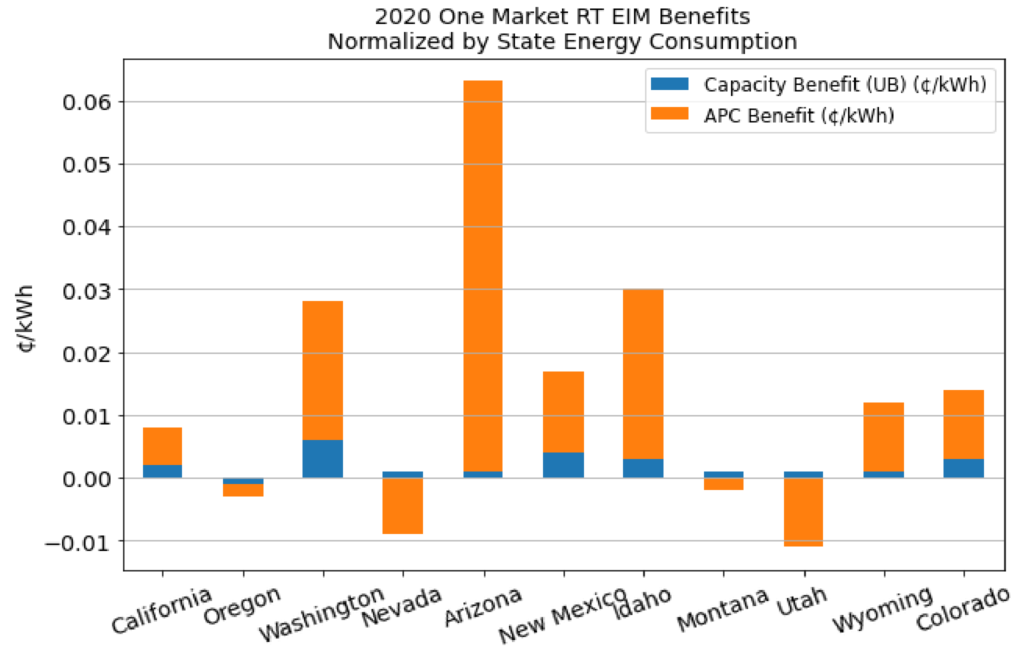
One Market EIM (Real-Time Only) Benefits

Results indicate a combined savings ranging $105M - $127M as the result of Western system consolidation into EIM-only market

- Shifting dispatch causes minor cost increases for Oregon, Nevada, and Montana, rest of states experience savings

State	Gross Benefits ($M)			Total Annual Benefits ($M)	
	Capacity Savings		APC Savings		
	Low Range	High Range	Base	Low Range	High Range
California	$0.00	$6.77	$18.14	$18.14	$24.91
Oregon	$0.00	-$0.53	-$0.87	-$0.87	-$1.40
Washington	$0.00	$6.04	$22.11	$22.11	$28.15
Nevada	$0.00	$0.48	-$3.39	-$3.39	-$2.91
Arizona	$0.00	$0.73	$41.71	$41.71	$42.44
New Mexico	$0.00	$2.62	$8.58	$8.58	$11.20
Idaho	$0.00	$0.80	$7.58	$7.58	$8.38
Montana	$0.00	$1.33	-$2.68	-$2.68	-$1.35
Utah	$0.00	$0.55	-$4.11	-$4.11	-$3.56
Wyoming	$0.00	$0.37	$4.35	$4.35	$4.72
Colorado	$0.00	$3.46	$13.44	$13.44	$16.90
Total	$0.00	$22.62	$104.87	**$104.87**	**$127.49**



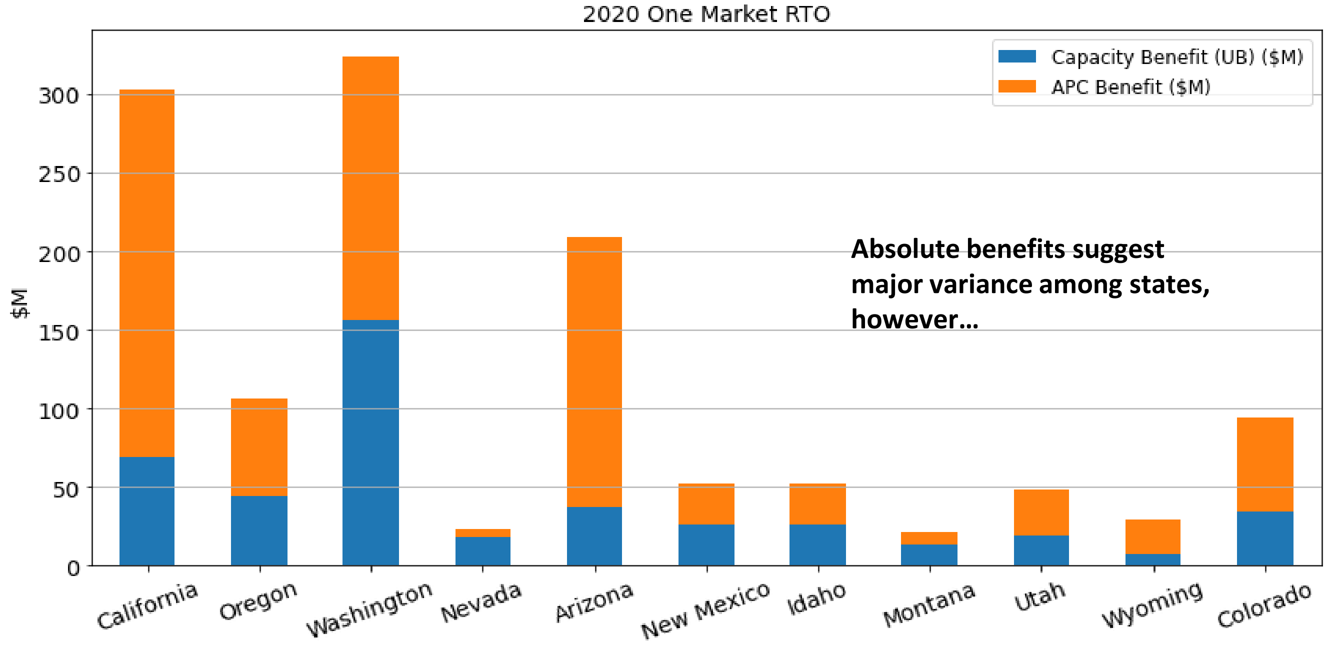


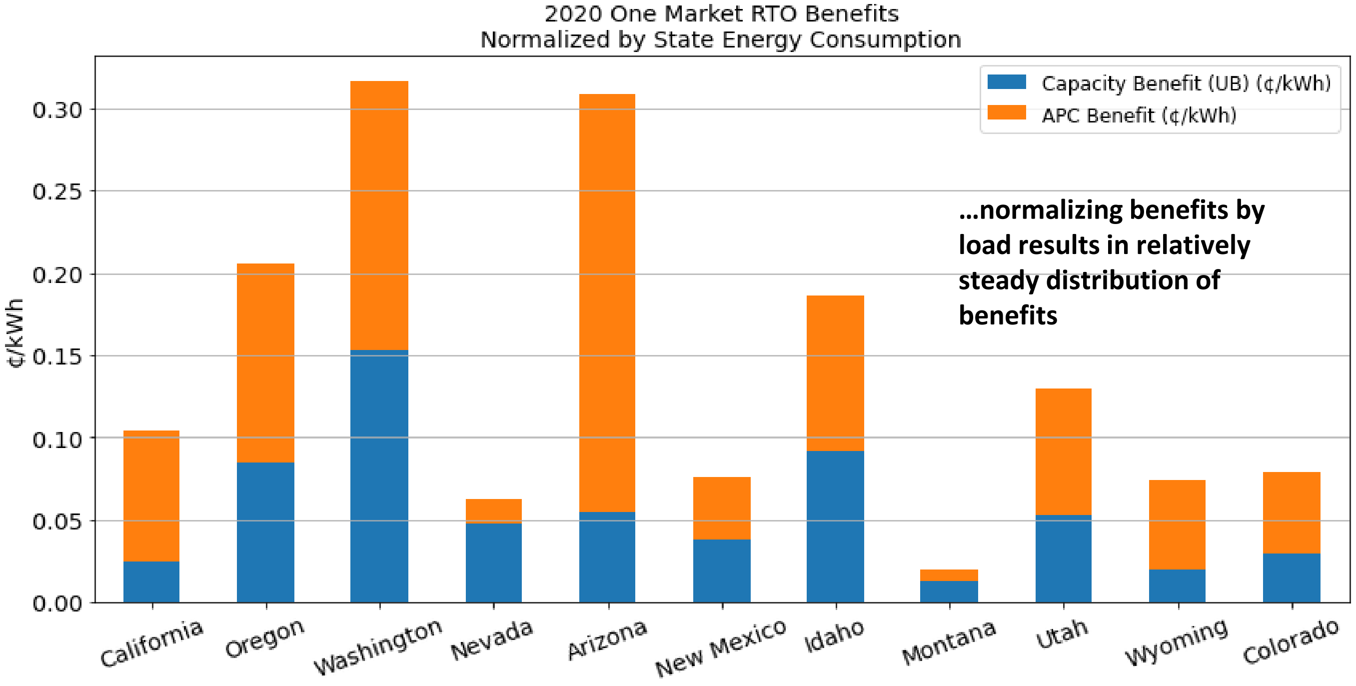
One Market RTO Benefits

Results indicate $1.3B in annual combined benefits as the result of Western RTO in 2020

- Approximately $453M in benefits achieved from capacity savings, and $811M from increased operational efficiency (reduced APC)
- Normalization of benefits relative to state's annual energy consumption illustrates relative benefits of RTO market expansion for each state

State	Gross Benefits ($M)		Total Annual Benefits ($M)
	Capacity Savings	APC Savings	
California	$69	$234	$303
Oregon	$44	$62	$106
Washington	$157	$168	$324
Nevada	$18	$5	$23
Arizona	$37	$172	$209
New Mexico	$26	$26	$52
Idaho	$26	$27	$53
Montana	$14	$8	$21
Utah	$20	$29	$48
Wyoming	$8	$21	$29
Colorado	$35	$60	$95
Total	$453	$811	$1,264





Key Observations from 2020 study

- Study estimates measurable gross benefits for most states under both market configurations
- RTO scenario has greater gross benefits than EIM scenario
  - Load diversity drives material portion of savings in RTO
  - Critical to recognize already-realized EIM benefits
- Normalizing savings by state load suggests benefits are consistent in order of magnitude (but not equal)
- Interstate trade of power significantly enhanced by market formation
  - Small (<1%) but still measurable impacts to emissions, mostly due to running more efficient generators
  - Minor impact to renewable energy curtailment
  - No changes to transmission congestion on major transmission paths

2030 Studies will answer majority of project-driving questions posed by Lead Team

- Benchmarking/test studies are underway
- Draft database is being compiled using best-available public information
- Key challenge so far: Representation of statutory public policy vs. voluntary goals or targets

Market and Regulatory Review Work Plan

Energy Strategies

Market & Regulatory Review

- "Market & Regulatory Review" designed to address more qualitative aspects of the Request from the Lead Team
  - ❖ Intended to help the states evaluate more qualitative aspects of different organized market configurations
  - ❖ Will culminate with the "Market Factor Scorecard"
  - ❖ Includes other areas of review, that do not fit squarely in the "Scorecard" format
- Lead Team approved the Work Plan for this effort in October
  - ❖ Work is underway to complete the work plan

Market Factor Scorecard Approach & metrics

- Work Plan identified two overarching state energy policy priorities (which are not mutually exclusive, but each state may weight these priorities differently)
  - ❖ Increased Use of Clean Energy Technologies
  - ❖ Reliable, Affordable Provision of Energy to Consumers
- Work Plan outlined relevant metrics for each overarching policy goal
- Next step is to evaluate each potential market construct based on its ability to facilitate the relevant metric
- Market constructs evaluated will be:
  - ❖ Bilateral Only
  - ❖ Real-Time Market
  - ❖ Day-Ahead Market
  - ❖ Regional Transmission Organization

Metrics for the Market Factor Scorecards

Icon	Meaning
Excellent	Market construct is expected to substantially support achievement of this metric
Very Good	Market construct is expected to mostly support achievement of this metric
Good	Market construct is expected to somewhat support achievement of this metric
Fair	Market construct is expected to minimally support achievement of this metric
Poor	Market construct is not expected to support achievement of this metric

Relevant Metrics for Increased use of Clean Energy Technologies

- Efficient grid operation which allows low (and zero) marginal cost resources to be dispatched and reducing overall costs of integrating clean electricity technologies
- Lower barriers to access high-quality renewable resource locations
- Expanded opportunities for clean electricity resources to be added to the grid (e.g. direct customer access to renewable/clean resource power purchase agreements)
- Enhanced financing opportunities and additional revenue streams for clean electricity technologies
- Facilitation of emissions reduction goals/requirements
- Transparent and timely information on pricing, resource operations, and emissions

Relevant Metrics for Reliable, Affordable Provision of Energy

- Efficient grid operation which reduces costs and increases flexibility of transactions
- Ability to reduce generation and transmission investment/capital costs
- Ability to unlock full potential of generation and transmission system to ensure reliable operations
- Enhanced visibility into electric system conditions to improve reliability
- Transparent and timely information available to consumer advocates and other stakeholders
- Long-term mechanisms to support a system with adequate electric resources and increased opportunities for cost-effective demand-side resource participation

Other Elements of the Market & Regulatory Review

- Two pieces of review of interest to the Lead Team didn't squarely fit in the Market Factor Scorecard approach
  - ❖Review of Likely Required Regulatory Approval Processes for each Market Construct
  - ❖Impacts of Market Constructs on State Regulatory Authority (with use of "Case Studies" where appropriate/available)
    - ➢ Integrated Resource Planning (and resource adequacy)
    - ➢ Transmission planning and prudence/cost recovery for transmission investments
    - ➢ Retail energy rates

Stakeholder suggestions for case studies welcomed

Next Steps and Future Meetings

Stakeholder Input Requested…

- 2030 study assumptions, especially feedback regarding:
  - Transmission additions
  - Representation of public policy vs. voluntary goals
  - Assumed coal retirements (see list developed by Lead Team)
- Assumption summaries are provided in Appendix for review

Request for Written Stakeholder Comments & Next Meetings

- **We invite the opportunity for stakeholders to provide written comments on the items discussed today**
- **Process for submitting comments:**
  - ❖ Written comments can be submitted to kfraser@energystrat.com through November 13th
  - ❖ Note that we will review comments, but will not respond specifically to each comment received
- **Upcoming meetings**
  - ❖ Anticipate late-Q4 meeting

Appendix

Core Questions

- **Foundational: The only market that we are "assuming" into the Status Quo future is planned expansion of the Western EIM footprint (announced entities). These 2020 and 2030 Status Quo cases will be our primary point of comparison for the other Core Studies.**

1. **In the near-term, what are the relative benefits of expanding EIM markets through either one West-wide footprint versus a two-market footprint system?**
   - 2020: EIM Status Quo vs. EIM One Market
   - 2020: EIM Status Quo vs. EIM Two Market B
2. **What is the 2020-2030 trajectory of benefits, if any, for a One Market RTO?**
   - 2020 RTO One Market vs. 2030 RTO One Market
3. **In the long-term, if the footprint of the Status Quo EIM does not grow, what incremental benefits are provided by adding services to include Day-ahead?**
   - 2030: EIM Status Quo vs. Day-ahead Status Quo
4. **In the long-term, what are the relative benefits of expanding the Status Quo EIM to a larger West-wide footprint while also expanding market services to either day-ahead or Full RTO?**
   - 2030: EIM Status Quo vs. Day-ahead One Market
   - 2030: EIM Status Quo vs. RTO One Market

How to read this terminology:

"EIM One Market"

$\underbrace{\text{"EIM}}_{\text{Market service}}\ \underbrace{\text{One Market"}}_{\text{Footprint}}$

Core Questions (continued)

5. **In the <u>long-term</u>, assuming a day-ahead market forms (but not an RTO), how do the benefits of Two Market footprints compare against the One Market footprint?**
   - 2030: Day Ahead One Market vs. Day Ahead Two Market B
6. **In the <u>long-term</u>, how do the benefits of Day-Ahead services compare with an RTO in a One Market footprint?**
   - 2030: Day Ahead One Market vs. RTO One Market
7. **In the <u>long-term</u>, how are the benefits of an RTO impacted by market footprints?**
   - 2030: RTO One Market vs. RTO Two Market A
   - 2030: RTO One Market vs. RTO Two Market B

Sensitivities

1. **In the <u>long-term</u>, how do benefits change if more transmission is built?**
   - 2030: EIM Status Quo vs. EIM Status Quo w/ Transmission
   - 2030: RTO One Market vs. RTO One Market w/ Transmission
   - 2030: RTO Two Market B vs. RTO Two Market B w/ Transmission
2. **In the <u>long-term</u>, how sensitive are RTO scenarios to a Federal or West-wide carbon pricing regime?**
   1. 2030: RTO One Market vs. RTO One Market w/ Carbon Price
   2. 2030: RTO Two Market A vs. RTO Two Market A w/ Carbon Price
   3. 2030: RTO Two Market B vs. RTO Two Market B w/ Carbon Price

Study Assumptions

Draft 2030 Study Assumptions for Review by Stakeholders

2030 Study Case Core Assumptions (DRAFT)

- **Market modeling assumptions are addressed in Work Plan document and are generally consistent with methods used in 2020 studies**

Assumption	Source	Data Summary
Demand	• 2030 ADS and for CAISO 2019 IEPR Mid-Mid forecast	Total System Peak = 167,261 MW
Fuel Prices	• Gas price sourced from CEC 2019 IEPR report (NAMGAS published in October 2019) • Coal prices based on 2030 ADS inputs • Other fuels consistent with 2030 ADS	Henry Hub Gas = \$3.41/mmBTU (2018\$) Coal = Average 2017-2019 price discounted by 25% to represent take or pay contracts

Generation Mix	• Existing generation plus adds from
	  ○ CPUC 2019 Reference System Plan (and bus mapping)
	  ○ WECC 2030 ADS
	  ○ Review of certain IRPs
	• Includes coal retirements identified by Lead Team and replacements, if available
		• Currently in development

GHG Prices	• California GHG policy modeled via Mid Trajectory based on 2019 IEPR carbon price projections • Applied to in-state generation and imports	2020: \$18.65/MT CO2 (2018\$) 2030: \$62.15/MT CO2 (2018\$)
Transmission Additions	• Based on review of regional transmission plans, interregional project submittals, and criteria established by Work Plan	• **See subsequent slides**
Thermal Unit Parameters	• Updated based on 2019 InterTech report commissioned by WECC • Also updated variable O&M rates for specific generators based on historical performance • Otherwise consistent with ADS	• Not applicable

Transmission Additions for 2030 Study (DRAFT)

- **Approach: Include <u>all</u> 230-kV and below additions by default and develop and apply screening criteria for the inclusion of regionally-significant upgrades above 230-kV**
  - Logic: Assume that 230-kV and lower upgrades are required for reliability
  - Include higher-voltage projects if they are likely to be constructed, the determination of which is made objectively through application of criteria
  - By not overbuilding system we will not forecast market benefits that are depending on yet-to-be approved or speculative transmission upgrades

				Pass one evaluation criteria to be included in 2030 case…						
Project	**Voltage (kV)**	**Region**	**Proponent**	**Under construction?**	**Granted a CPCN or similar, by relevant regulatory body**	**Approved by an independent system operator board**	**Planned to be in-service prior to 2024 and are included in an approved or acknowledged IRP action plan**	**PASS?**	**Note**	**Links**
Boardman to Hemingway (B2H)	500	NG	Idaho Power	No	No	No	No	**NO**	2019 IPCO 2nd Amended IRP adds project in 2026	IRP
Gateway South (Aeolus - Mona)	500	NG	PacifiCorp	No	No	No	Yes	**YES**	Complete or contingent acknowledgement in 2019 IRP, 2023 add	IRP
Gateway West D.1 (Windstar - Aeolus)	230	NG	PacifiCorp	No	No	No	No	**NO**	Earliest COD is 2023 but not included in 2019 IRP Action Plan	IRP
Gateway West D.2 (Aeolus - Bridger)	500	NG	PacifiCorp	Yes	Yes	No	Yes	**YES**	Under construction	IRP
Gateway West D.3 (Bridger - Populus)	500	NG	PacifiCorp	No	No	No	No	**NO**	Does not meet criteria, still permitting	IRP
Gateway West E & E.2 (West of Populus)	500	NG	PacifiCorp	No	No	No	No	**NO**	Does not meet criteria, still permitting	IRP
Antelope to Goshen	345	NG	PacifiCorp	No	No	No	No	**NO**	Gen-tie project, does not meet criteria	IRP
Cascade Renewable Transmission System (DC	440	NG	PowerBridge	No	No	No	No	**NO**	Regional proposal to NorthernGrid	
Loco Falls Greenline	230/500	NG	Absaroka	No	No	No	No	**NO**	Regional proposal to NorthernGrid	Project site
Cross-Tie Transmission Project	500	NG/WC	TransCanyon	No	No	No	No	**NO**	Interregional proposal to NorthernGrid, WestConnect	ITP plan
Southwest Intertie Project North (SWIP)	500	NG/WC/CAISO	LS Power	No	No	No	No	**NO**	Interregional proposal to NorthernGrid, WestConnect, CAISO	ITP plan
TransWest Express (AC/DC)	500	NG/CAISO	TransWest	No	No	No	No	**NO**	Interrregional proposal to NorthernGrid, CAISO	ITP plan
Delaney-Colorado River (TenWest Link)	500	CAISO	DCR Trans.	Yes	Yes	Yes	No	**YES**	Under construction	Site
Mesa 500 kV Substation Project	500	CAISO	SCE	Yes	Yes	Yes	No	**YES**	Under construction; identified in CAISO 2019-2020 TPP	Site
Round Mountain / Gates Reactive Support	500	CAISO	LS Power	No	No	Yes	No	**YES**	Identified in CAISO TPP	
North Gila Imperial Valley #2	500	CAISO	NGIV2	No	No	No	No	**No**	Submitted in prior TPP cycles	Site
Northwst Tie Upgrade	138	CAISO/WC	GridLiance	No	No	No	No	**No**	Interregional proposal to CAISO, WestConnect	ITP plan

Notes

Harry Allen-Eldorado (DesertLink) is in-service in 2020

Case includes Western Spirit and other additions to WestConnect Base Transmission Plan

CAISO project submittals are not listed

Public Policy Modeling (DRAFT)

- **Study requires that 2030 production cost modeling runs include clean energy resources commensurate with state policies**
- **In addition, it is prudent to have the model also reflect achievement of goals/targets that are voluntary and are being pursued by utilities, cities, corporations, and municipalities**
  - ❖ If the PCM includes only enough resources to meet the statutory policy requirements, modeling may **understate** the amount of clean energy likely to be on the grid in 2030 and as a result mis-state the impact of regional market expansion.
  - ❖ Therefore, we propose an approach that estimates a clean energy target as a percentage of retail sales that reflects achievement of state policies as well as known voluntary goals.
    - ➢ Much of the data we used to set the clean energy targets is from a NWPCC System Analysis Advisory Committee held on August 5, 2020 in which the SAAC reviewed clean energy constraints/requirements that the NWPCC staff generated to reflect statutory requirements and announced goals by utilities, cities, and counties.

Summary of State Policy Requirements

State	RPS %	Target Date	State GHG Reduction Mandate?	No Coal Policy?	Notes
Arizona	15%	2025	No	No	15% by 2025 is RPS requirement Major utilities have clean/sustainable goals that exeed this
California	60%	2030	Yes - price	Yes	SB100: 100% zero carbon resources by 2045 and 60% RPS by 2030
Colorado	60%	2030	Yes	No	Based on administrative goal of 100% by 2040 SB19-236 requires Xcel to plan for 80% GHG emission reduction (from 2005) by 2030 HB19-1261 requires 50% economy-wide reduction in GHG (from 2005) by 2030
Idaho	N/A	N/A	No	No	Two of Idaho’s major investor-owned utilities (Idaho Power and Avista) are pursuing 100% clean energy goals by 2045
Montana	15%	2015	No	No	15% RPS by 2015
Nevada	50%	2030	No	No	SB 358: 50% RPS by 2030 and 100% clean goal by 2050
New Mexico	50%	2030	No	No	SB 489 ETA: 80% RPS by 2040 (IOU) and 2050 (REAs); 100% clean by 2045 (IOU) and 2050 (REA)
Oregon	50%	2040	No	Yes	SB 1547: 50% RPS for IOU by 2040; no coal after 2030
Utah	20%	2025	No	No	HB 411 (Community Renewable Energy Act): Allows for communities served by RMP to move to 100% net renewable energy
Washinton	80%	2030	No	Yes	SB 5116: 80% non-emitting 2030 sales, 100% by 2045; no coal after 2026
Wyoming	N/A	N/A	No	No	Senate File 159 requires utilities to attempt to sell coal plants before retirement

Clean Energy Modeling Targets (DRAFT)

- **Purpose of clean energy targets is to estimate potential build required to achieve both statutory and voluntary obligations**
- **Clean sources such as nuclear and hydro are included in the accounting for the target depending on that nature of the goals and/or policy requirements**
- **Calculation method performed by NWPCC establishes state-level target for all retail load in state by rolling up RPS, clean energy targets/policies, and voluntary commitments**

Assumed Clean Energy Modeling Targets

State	Clean Energy % for 2030	Carbon Price?	Source	Notes	Include Nuclear and Hydro?
Arizona	38%	No	NWPCC 2021 Plan	Assumes APS 65% clean by 2030 SRP 20% sustainable by 2020, TEP 30% RE by 2030	Yes
California	60% (RPS)	Yes	SB100	RPS consistent with SB100 requirements, modeling reflects AB32 price forecasts	No
Colorado	60%	No	NWPCC 2021 Plan	Pseudo admin goal. Reflects PSCO, PRPA, PV REA, Holy Cross, and city/county clean energy goals for 2030.	Yes
Idaho	10%	No	NWPCC 2021 Plan	Reflects targets by Avista, Idaho Power, and Boise clean energy goals. Based on load weighting between the three entities relative to the state retail sales	Yes
Montana	18%	No	NWPCC 2021 Plan	Reflects Missoula & Helena 100% clean targets and 15% RPS	Yes
Nevada	50% (RPS)	No	SB 358	Consistent with SB 358 requirements	No
New Mexico	50% (RPS)	No	SB 489 ETA	Utility voluntary goals roughly match ETA	No
Oregon	27%	No	NWPCC 2021 Plan	RPS + cities/counties with clean goals (100% clean by 2035) and adjustment by utility size. Reflects weighted average of IOU targets (50%) and municipalities (5%-25%)	No
Utah	50%	No	NWPCC 2021 Plan	Assumes 37% of state load commit to HB411 100% renewable by 2030	No
Washinton	80%	No	CETA	Assume city/county goals do not exceed CETA	Yes
Wyoming	0%	No	N/A	No voluntary goals specific to state	N/A
**When required targets are adjusted to account for equivalent target for 100% of state retail sales*					

Coal Retirements

Plant Name	Utility	Capacity (MW)	Assumed Retirement Date
Centralia 1	TransAlta	670	2020
Boardman	PGE, Idaho power	601	2020
Cholla 4	PacifiCorp	380	2020
Escalante	Tri-State	247	2020
North Valmy 1	NV Energy, Idaho Power	254	2021
Comanche 1	PSCo	325	2022
San Juan 1 & 4	PNM, TEP, munis	847	2022
Martin Drake	Colorado Springs Utilities	208	2023
Jim Bridger 1	PacifiCorp, Idaho Power	531	2023
Comanche 2	PSCo	335	2025
Cholla 1	APS	116	2025
Cholla 3	APS	271	2025
North Valmy 2	NV Energy/Idaho Power	290	2025
Naughton 1 & 2	PacifiCorp	357	2025
IPP	Multi (UT and CA municipals)	1,800	2025
Craig 1	Tri-State, SRP, PRPA, PacifiCorp, PSCo	428	2025
Centralia 2	TransAlta (contract with PSE)	670	2025
Dave Johnston 1-4	PacifiCorp	760	2027
Springerville 1	TEP	387	2027
Jim Bridger 2	PacifiCorp, Idaho Power	527	2028
Craig 2	Tri-State, SRP, PRPA, PacifiCorp, PSCo	670	2028
Colstrip 3	See (1)	740	2029
Craig 3	Tri-State	601	2029
Hayden 1-2	PSCo, PacifiCorp, SRP; See (3)	380	2029
Rawhide 1	Platte River Power Authority	280	2029
Ray Nixon Power Plant	Colorado Springs Utilities	208	2029
	TOTAL RETIREMENTS BY 2030	12,883	

2030 study year requires assumptions surrounding future coal retirements

- Approach is to model announced and planned coal retirements
- Primary data sources are announcements from generator owners and utility resource plans (there have been new announcements since the last meeting)
- Plan to replace capacity with best-available information on resource plans (generally IRPs)
  - Adequacy issues in the model will be addressed as necessary
- The following slides summarize units that are announced/planned to retire prior to and during 2030 and include some changes from the June meeting, based on Lead Team feedback and discussions

Reminder: This is a market-benefit study so the most important thing is to keep a reasonable resource portfolio consistent across scenarios.

Notes:

(1) PSE (25%), PGE (20%), Avista (15%), PacifiCorp (10%), Talen (30% of Unit 3), NorthWestern (30% of Unit 4)

(2) 2026 per PacifiCorp, 2030 per Tri-State

(3) Based on PacifiCorp 2019 IRP and PSCo 80% carbon reduction goal (and need to retire in time to meet a 2030-year Colorado carbon compliance obligation)

(4) We are listing the last year in which the unit is planned to operate (2029 indicates a retirement prior to 2030)

Supplemental Results

2020 Study Results: State-specific Results

State-level APC Changes ($M)

APC Change from Status Quo Case	2020 One Market EIM		2020 One Market RTO	
	$M	(%)	$M	(%)
AZ	($42)	-2.9%	($172)	-12.0%
CA	($18)	-0.4%	($234)	-5.8%
CO	($13)	-1.4%	($60)	-6.5%
ID	($8)	-2.3%	($27)	-8.1%
MT	$3	1.5%	($8)	-4.3%
NM	($9)	-2.5%	($26)	-7.6%
NV	$3	0.4%	($5)	-0.6%
OR	$1	0.2%	($62)	-11.3%
UT	$4	0.8%	($29)	-5.3%
WA	($22)	-3.0%	($168)	-22.8%
WY	($4)	-2.0%	($21)	-9.6%
TOTAL	**($105)**	**-1.0%**	**($811)**	**-8.0%**

- **Changes are relative to Status Quo scenario**
- **Expanded EIM has small benefit for most states (never more than 3%)**
- **Expanded RTO benefits all states with an 8% average reduction in APC**

What drives operational savings for each state?

	EIM Expansion Case	RTO Expansion Case
AZ	Higher production costs offset by increased revenues from exports	Higher production costs offset by increased export revenue
CA	Increased purchases offset by higher export revenue and lower production costs	Less in-state production, more imports, and higher-value exports
CO	Increased purchases offset by higher revenues from exports and lower production costs	Benefits from lower production costs and increase in export revenues
ID	Decrease in production costs drives savings	Decrease in production costs and more reliance on imports drives benefits
MT	Slight increase due to higher production costs not being fully offset by decrease in imports	Higher export revenues drive benefits
NM	Benefits from increased export revenue	Benefits from lower production costs and increased export revenue
NV	Decrease in production costs offset by greater imports	Load served with lower cost imports versus local generation
OR	Increased revenue from exports drives benefits	Increased revenue from exports and lower production costs drives benefits
UT	Lower production costs offset by reduced sales and more imports	Increase in exports exceeds small increase in production costs
WA	Increased revenue from exports drives benefits	Increased revenue from exports drives benefits
WY	More sales offsets higher production cost	Increase in exports exceeds increase in production costs

2020 Study Results: State Dashboard

Key
A: Business as Usual
B: One Market EIM
C: One Market RTO

		APC Components ($M)				Generation (MWh)										
State	Case	APC ($M)	Production Cost ($M)	Imports ($M)	Exports ($M)	Nuclear	Coal	Hydro	Gas	PS	BESS	Geothermal	Biomass	Other	Solar	Wind
AZ	A	1,435	1,576	(115)	257	33,146,856	4,051,567	5,859,151	61,230,134	270,872	21,301	0	175,925	0	4,531,940	688,563
	B	1,393	1,617	(109)	333	33,146,856	3,919,898	5,859,151	63,734,550	289,552	21,301	0	175,925	0	4,538,483	688,563
	C	1,263	1,885	(138)	761	33,146,856	4,273,892	5,859,151	78,749,723	241,242	21,301	0	175,925	0	4,551,547	688,563
CA	A	4,063	3,856	(314)	107	19,676,160	0	28,177,220	89,532,349	2,981,400	492,382	11,910,210	5,629,158	193,567	30,702,101	24,468,558
	B	4,044	3,845	(338)	139	19,676,160	0	28,177,282	89,047,002	3,371,993	490,892	11,910,210	5,629,158	192,443	30,769,022	24,463,270
	C	3,829	3,330	(697)	198	19,676,160	0	28,177,515	78,068,825	2,830,738	478,120	11,910,210	5,629,158	182,324	30,896,265	24,498,144
CO	A	928	971	(17)	60	0	23,677,970	1,453,812	19,183,714	388,103	0	0	0	0	1,173,670	10,259,237
	B	914	960	(52)	98	0	23,020,245	1,453,812	17,731,124	249,646	0	0	0	0	1,173,677	10,259,237
	C	867	927	(68)	128	0	23,245,682	1,453,812	17,920,498	255,369	0	0	0	0	1,173,677	10,259,237
ID	A	330	263	(111)	44	0	0	8,802,282	2,928,308	0	0	0	500,484	100,191	581,155	2,388,319
	B	322	251	(110)	39	0	0	8,802,282	2,610,787	0	0	0	500,484	95,694	581,108	2,388,319
	C	303	226	(136)	58	0	0	8,802,282	1,746,035	0	0	0	500,484	106,065	581,213	2,388,319
MT	A	174	121	(83)	30	0	11,948,368	9,538,761	436,237	0	0	0	7,739	26,233	160,274	2,448,975
	B	177	129	(79)	31	0	12,083,669	9,538,686	558,137	0	0	0	7,929	26,233	161,233	2,451,954
	C	167	122	(84)	40	0	12,075,642	9,538,705	391,973	0	0	0	8,475	26,233	162,539	2,458,084
NM	A	346	338	(21)	13	0	5,535,165	254,898	6,402,450	0	0	0	18,125	2,485	818,494	5,861,813
	B	337	336	(21)	20	0	5,330,940	254,898	6,817,312	0	0	0	18,125	2,485	820,086	5,861,829
	C	319	314	(34)	29	0	4,854,524	254,898	6,816,173	0	0	0	18,125	2,485	820,683	5,861,830
NV	A	823	700	(134)	10	0	1,763,315	2,411,155	26,740,243	0	0	3,491,766	0	0	6,304,694	440,791
	B	826	675	(157)	5	0	1,708,108	2,411,155	25,758,332	0	0	3,491,766	0	0	6,304,632	440,791
	C	818	460	(362)	4	0	1,581,720	2,411,155	18,421,771	0	0	3,491,766	0	0	6,305,267	440,791
OR	A	552	715	(79)	242	0	770,708	21,967,425	17,162,357	0	0	173,010	645,538	0	466,005	11,551,956
	B	553	717	(82)	246	0	880,349	21,967,425	17,094,771	0	0	173,010	644,270	0	467,764	11,555,269
	C	490	650	(151)	311	0	425,711	21,967,425	17,889,136	0	0	173,010	643,982	0	473,692	11,594,852
UT	A	541	626	(9)	94	0	21,659,700	518,422	11,042,936	0	0	403,218	0	0	2,438,662	1,254,158
	B	545	597	(15)	66	0	20,611,006	518,422	10,708,968	0	0	403,218	0	0	2,438,662	1,254,158
	C	513	634	(9)	131	0	21,076,080	518,422	12,180,354	0	0	403,218	0	0	2,438,662	1,254,158
WA	A	734	753	(568)	586	10,215,792	1,884,221	83,664,131	18,981,942	9,381	0	0	1,791,781	0	0	11,127,821
	B	712	745	(570)	602	10,215,792	1,865,267	83,664,131	18,987,177	9,381	0	0	1,791,781	0	0	11,149,809
	C	567	802	(542)	777	10,215,792	2,537,615	83,664,131	20,388,325	9,381	0	0	1,791,781	0	0	11,193,878
WY	A	222	275	(3)	56	0	29,525,304	676,470	13,700	0	0	0	0	139	288,047	6,506,911
	B	218	278	(4)	64	0	31,679,190	676,470	15,674	0	0	0	0	139	288,047	6,506,940
	C	201	288	(3)	90	0	32,131,905	676,470	19,520	0	0	0	0	139	288,047	6,506,940

2020 Study Results: Reduction in renewable curtailment not a material driver of benefits in 2020 timeframe

Key	
	A: Business as Usual
	B: One Market EIM
	C: One Market RTO

- **Renewable curtailment is low, with about 0.3% of renewable energy curtailed in the Status Quo case**
- **Curtailment changes between the two market scenarios are minimal, with the largest curtailment benefit occurring under the RTO scenario where curtailment drops 17% by about 374 GWh**
  - ❖ For reference, CAISO had a total of roughly 573 GWh of curtailments in April and May of 2020 (combined)
  - ❖ The largest avoided curtailment benefits occur in California, Montana, Oregon, and Washington
- **Some curtailment caused by transmission congestion is persistent across all studies (e.g., Utah) and cannot be addressed by market coordination**

Curtailment %

State	Case	Solar	Wind
AZ	A	0.4%	0.0%
	B	0.3%	0.0%
	C	0.0%	0.0%
CA	A	1.6%	0.5%
	B	1.4%	0.5%
	C	1.0%	0.3%
CO	A	0.0%	4.7%
	B	0.0%	4.7%
	C	0.0%	4.7%
ID	A	0.0%	0.0%
	B	0.0%	0.0%
	C	0.0%	0.0%
MT	A	1.5%	0.5%
	B	0.9%	0.4%
	C	0.1%	0.2%
NM	A	0.3%	2.2%
	B	0.1%	2.2%
	C	0.0%	2.2%
NV	A	5.3%	0.0%
	B	5.3%	0.0%
	C	5.3%	0.0%
OR	A	2.6%	0.9%
	B	2.2%	0.9%
	C	1.0%	0.6%
UT	A	13.8%	0.0%
	B	13.8%	0.0%
	C	13.8%	0.0%
WA	A	0.0%	0.7%
	B	0.0%	0.5%
	C	0.0%	0.1%
WY	A	0.0%	0.0%
	B	0.0%	0.0%
	C	0.0%	0.0%

Utilization of Key Transmission Paths

Path	Path Name	Direction	States	2020 SQ RT EIM		2020 1Mkt RT EIM		2020 1Mkt RTO	
				U75	U99	U75	U99	U75	U99
P03	P03 Northwest-British Columbia	S→N	WA→BC	0.1%	0.0%	0.1%	0.0%	0.9%	0.0%
P06	P06 West of Hatwai	E→W	ID→WA	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
P08	P08 Montana to Northwest	E→W	MT→ID/WA	3.0%	0.1%	2.0%	0.1%	3.2%	0.1%
P19	P19 Bridger West	E→W	WY→ID	13.9%	1.7%	15.2%	1.2%	11.9%	1.0%
P32	P32 Pavant-Gonder InterMtn-Gonder 230 kV	E→W	UT→NV	0.8%	0.0%	2.2%	0.1%	1.1%	0.1%
P36	P36 TOT 3	N→S	WY/NE→CO	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
P39	P39 TOT 5	W→E	CO	0.0%	0.0%	0.4%	0.0%	2.0%	0.1%
P46	P46 West of Colorado River (WOR)	E→W	NV/AZ→CA	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
P47	P47 Southern New Mexico (NM1)	N→S	AZ→NM	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
P48	P48 Northern New Mexico (NM2)	NW→SE	NM	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
P49	P49 East of Colorado River (EOR)	E→W	AZ→NV/CA	0.0%	0.0%	0.0%	0.0%	2.1%	0.0%
P65	P65 Pacific DC Intertie (PDCI)	N→S	OR/WA→CA	20.2%	2.0%	22.8%	2.0%	29.8%	4.9%
P66	P66 COI	N→S	OR→CA	2.7%	0.0%	2.8%	0.0%	9.9%	0.0%

U75: % of year flow across path meets or exceeds 75% of the path's transfer limit

U99: % of year flow across path meets or exceeds 99% of the path's transfer limit

Increases in…

AZ Exports, CA/NV Imp

NW Exports, CA Imports

- **Changes in utilization rates on key transmission paths sheds light on how energy interchange between the states adapts to new markets**
- **With an expanded real-time market (EIM) across the West, U75 and U99 rates change minimally across the major paths**
- **RTO market modeling causes a more significant impact on flows for a few of the major paths, suggesting that an RTO more effectively promotes trade between the Western states relative to an expanded real-time market.**
  - The paths between the Northwest and California and between the Southwest and California experience the largest change. Increased flows across these paths aligns with the shift in exports and imports between these regions discussed in the APC analysis, with California becoming a major importer of its two neighboring regions
  - Congestion across the Pacific DC Intertie a possible concern in this scenario given its increased U99 rate

Market Footprint Detail by Balancing Authority

Status-Quo (BAs)	One Market	Two Market A	Two Market B
CAISO	All WECC Balancing Areas (excluding AESO)	<u>Footprint A1</u>	<u>Footprint B1</u>
PacifiCorp		CAISO	PSCo
NV Energy		BANC	WACM
Puget Sound Energy		TID	WAUW
Arizona Public Service		LADWP	<u>Footprint B2</u>
Portland General Electric		IID	All remaining WECC Balancing Areas (excluding AESO)
Idaho Power		<u>Footprint A2</u>	
Powerex		All remaining WECC Balancing Areas (excluding AESO)	
SMUD (BANC Phase 1)			
Seattle City and Light			
Salt River Project			
LADWP*			
PNM*			
BANC* (BANC Phase 2)			
WAPA-Sierra Nevada*			
Northwestern Energy*			
TID*			
Avista*			
Tucson Electric Power*			
Tacoma Power*			
BPA*			
PSCO*			
Separate Market for WACM & WAUW*			

***These entities will join (or create) a Real-Time Market in 2021 or later, and thus will be included in the Status Quo for 2030, but not for 2020**