Renewable Resources and Transmission in the West:
Interviews on the
Western Renewable Energy Zones Initiative

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Western Governors' Association

Prepared by Regulatory Assistance Project for Western Governors' Association

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Contents

Figures and Tables

Acronyms

AESO – Alberta Electric System Operator
BPA – Bonneville Power Administration
CAISO – California Independent System Operator
CPCN – Certificate of Public Convenience and Necessity
CREPC – Committee on Regional Electric Power Cooperation
FERC – Federal Energy Regulatory Commission
IRP – Integrated resource plans or planning
LSE – Load-serving entity
MW – Megawatt
PUC – Public utility (or utilities) commission. See list of government agencies interviewed for other names used by Western states.
RFP – Request for proposals
RPS – Renewable portfolio standards
RTO – Regional transmission operator
SPSC – State-Provincial Steering Committee
TEPPC – Transmission Expansion Planning Policy Committee
WAPA – Western Area Power Administration
WECC – Western Electricity Coordinating Council
WIEB – Western Interstate Energy Board
WGA – Western Governors' Association
WREZ – Western Renewable Energy Zones

Utilities and Government Agencies Interviewed

Utilities
Arizona Public Service
Avista
BC Hydro
Colorado Springs Utilities
El Paso Electric
Eugene Water and Electric Board
Idaho Power
Imperial Irrigation District
Los Angeles Department of Water and Power
NV Energy
NorthWestern
Pacific Gas & Electric
PacifiCorp
Portland General Electric
Public Service Company of Colorado
Public Service Company of New Mexico
Puget Sound Energy
Sacramento Municipal Utility District
Salt River Project
San Diego Gas & Electric
Seattle City Light
Southern California Edison
Tacoma Power
Tri-State Generation and Transmission
Tucson Electric

State Public Utility Commissions
Arizona Corporation Commission
California Public Utilities Commission
Colorado Public Utilities Commission
Idaho Public Utilities Commission
Montana Public Service Commission
New Mexico Public Regulation Commission
Nevada Public Utilities Commission
Oregon Public Utility Commission
Utah Public Service Commission
Washington Utilities and Transportation Commission
Wyoming Public Service Commission

Provincial Energy Ministries
Alberta Energy
British Columbia Ministry of Energy and Mines

Executive Summary

The Western Renewable Energy Zones (WREZ) initiative aims to develop areas with abundant, high-quality renewable resources in the Western Interconnection – WREZ “hubs” – and establish an efficient network of interstate transmission lines to deliver the energy to load centers. The map in the centerfold of this report shows the WREZ hubs and existing transmission lines, as well as the 2022 Common Case Transmission Assumptions and other proposed lines used in regional transmission planning.[1] While some of these lines will reach WREZ hubs, most will remain inaccessible. Continued isolated procurement by individual utilities will not lead to major development of these renewable-rich areas and the requisite transmission.

The West has a long history of collaboration on thermal power plants and transmission. But renewable resources are different. They typically can be developed in small increments and short timeframes, so the drivers for joint development in the past – mainly sharing the cost and risk of large, capital-intensive projects – may not be in play.

Still, coordinated resource procurement – joint solicitations or simply aligning timing and potentially locations for resource procurement – could support WREZ development. Retooling the West’s traditional collaborative model could achieve economies of scale and a critical mass of transmission needs in the same timeframe that utilities acting alone cannot achieve.

Western Governors’ Association (WGA) commissioned interviews with 25 utilities, 11 public utility commissions (PUCs) and two provincial energy ministries to learn their views on potential collaboration to develop WREZ hubs. The interviews also collected important contextual information on resource planning and procurement, as well as transmission planning and development. In addition, WGA solicited opinions on market mechanisms to support development of higher levels of renewable resources in the West, next steps for the WREZ initiative, and issues of interest for regional discussion.

This report details the results of the interviews and the modeling that kicked off the discussions, with additional information provided for context. To allow for frank discussions, interviewees were advised that results would be presented in aggregate with exceptions, such as the utility’s preferred renewable energy zones. Following are key findings summarized from the first five chapters of this report. Chapter 6 presents interviewees’ recommendations on possible next steps for the WREZ initiative and issues of interest for regional discussions.

Key Findings

Preferred Renewable Energy Areas (Chapter 1)

- **In many cases, the utilities’ preferred renewable energy areas are not in sync with resources determined to be most economic by WREZ modeling** (Table 4 and Table 5). By design, the model makes its selections only from areas with high concentrations of high quality resources. The model does not consider constraints on resource location under state renewable energy requirements. In addition, the difference in adjusted delivered cost of energy for wind vs. solar is within the model’s margin of error for some combinations of WREZ hubs and load centers.

[1] Common Case Transmission Assumptions were called “foundational” lines in the Western Electricity Coordinating Council’s (WECC’s) 10-Year Regional Transmission Plan for 2020. Differences in lines assumed for the 2022 plan are the result of changing circumstances. See Chapter 3 for a discussion of foundational lines. For the 2022 transmission plan, *see* “TEPPC 2022 Common Case Transmission Assumptions” (slides 20 and 22), Dec. 9, 2011, http://www.wecc.biz/committees/BOD/TEPPC/20111209/Lists/Presentations/1/111209_2022CCTA_PPT_RTEPWEBINAR.pdf.

After cost, utilities cited availability of transmission to deliver energy to load centers as the most important reason for the utilities' preferred renewable energy areas.

- Some **16 WREZ hubs are of interest to utilities that together serve multiple states** (Table 6).

Resource Planning and Procurement (Chapter 2)

- **Utilities are focused on developing renewable resources in or close to their service areas.** Among the reasons is that resources close to load may not require new high-voltage transmission and, therefore, are easier to develop in a more incremental manner. Even where transmission capacity is available, the economics of distant, higher quality resources may be ruined by pancaking of charges – purchasing transmission service separately from each provider whose lines the power crosses to reach loads. Furthermore, renewable energy requirements in many states, enacted in part for economic development, limit out-of-state acquisitions. In-state resources also are a more obvious nexus with state public interest standards for siting and cost recovery, reducing development timelines and risk for utilities.
- **Utilities serving states without aggressive renewable energy requirements find it unlikely that they will be required to meet a 33 percent renewable resource target in the next 10 or 20 years.**
- **Utilities generally are uncertain about the point in time when they might access distant, high-quality resources**, rather than rely on closer sites even if they are lower quality. One utility said it has already reached this crossover point, with some projects requiring up to 100 miles of radial transmission to be cost-effective today. Another said the crossover point could occur in one year or 10 years in the future, depending on the cost of resources that bid into its solicitations. Some utilities do not see a crossover point occurring in the next 10 years, if at all.
- **Utilities are not interested in resources from WREZ hubs unless transmission to the hub already exists or there is a high degree of certainty for the timely completion of transmission to the hub.**
- **Diversifying the types of renewable resources acquired is an increasingly important driver for utility resource selection**, particularly with increasing levels of variable energy resources and related integration concerns.
- **Inconsistent and uncertain state and federal policies pose a barrier to efficient development of renewable resources, according to the utilities interviewed.** Commonly cited examples include differing renewable portfolio standards (RPS), changes in an individual state's RPS policies, and failure to establish stable federal tax credits. In addition, varying requirements for siting transmission facilities across state and provincial boundaries drive up the complexity, timelines, cost and risk for accessing out-of-state resources.
- Utilities and most state regulators interviewed believe **in-state preferences for renewable resources should be eliminated in order to create a level playing field** where the market would signal efficient investments and allow utilities to access the cheapest resources over a larger geographic area.
- **The complexity and length of resource planning and procurement processes do not match the short timelines for developing renewable energy projects**, making it difficult to take advantage of time-limited opportunities.
- **Utilities are increasingly wary of making investments in renewable resources and transmission in advance of the need for meeting RPS targets** – or in anticipation of additional transmission service requests – without strong indications that regulators will grant full cost recovery.
- **"Regulatory lag" – the amount of time between utility cost recovery and expenditures – is a fundamental issue for utilities for renewable resource and transmission development.** In

jurisdictions without provisions to address this concern, utilities may be reluctant to invest in long lead-time and capital-intensive projects.

- **Utilities largely do not specify the type or location of renewable resources in their resource plans or resource solicitations.** Instead, they rely on *results* of competitive processes to determine characteristics of resources procured.
- **Nearly all utilities believe the cost of generation from renewable resources will continue to trend downwards**, both for distributed and utility-scale generation. They also believe utility-scale generation will continue to be less costly than customer-sited distributed generation.
- **About one-quarter of the utilities interviewed include the potential impact of future carbon regulation in their resource planning or procurement processes. About half also model the potential impact of criteria air pollutants**. The dominant view is that while carbon regulation and increasingly stringent RPS requirements may increase the *levels* of renewable resources utilities acquire, the *location* of these resources would remain largely unchanged.
- **Utilities are just beginning to consider how smart grid technologies, reductions in thermal plant operations and intra-hour transactions might free up transmission capacity.** Some utilities said there are insufficient drivers to develop renewable resources to take advantage of freed-up transmission capacity on existing lines, or the amount of capacity may not be large enough to affect development.

Transmission Planning (Chapter 3)

- **Most utilities said they have adequate transmission arrangements in place to meet current renewable energy requirements over the next 10 years** assuming anticipated loads and continued resource development close to their service areas.
- **Transmission options are not thoroughly evaluated in integrated resource planning (IRP) processes, and most jurisdictions do not require utilities to submit separate transmission plans for review.** Meantime, resource plans have limited influence on transmission plans. The time horizon for the IRP action plan for near-term activities to acquire the identified resources is short, and competitive bidding is more determinative of actual resource acquisition and transmission needs.
- **By and large, revised Federal Energy Regulatory Commission (FERC) requirements have alleviated earlier restrictions on communication within the utility that created roadblocks to coordinated transmission and resource planning.** Still, some transmission planners are unable to communicate with resource planners to the extent they would like and feel limited in taking proactive roles.
- **"Foundational" lines in WECC's 2020 transmission plan (called Common Case Transmission Assumptions for the 2022 plan) – those assumed to have a high likelihood of being built over the next 10 years for the purpose of regional transmission planning – will affect where many of the utilities acquire renewable resources.** However, these lines will have little influence on resource acquisition decisions for the rest of the utilities interviewed for a variety of reasons, including adequate local resources to meet state renewable energy requirements.
- **Several utilities expect some of the additional planned ("potential") lines to be completed in the same timeframe as the foundational lines and affect their acquisition of renewable resources** (Table 10).
- According to respondents, **subregional planning groups play an important facilitative role in bringing together utilities and other stakeholders to share information and identify common needs and may serve as a forum for coordinating WREZ development.**

- **Generally utilities do not believe that subregional or regional planning for renewable resources is necessary for developing transmission to WREZ hubs, beyond the work done in transmission planning forums.** Government officials expressed more support for this concept.
- However, **utilities and government officials recommend that subregional planning groups identify optimal transmission build-outs to WREZ hubs of common interest, rather than focus solely on system problems such as congestion.** Government officials also recommend that subregional planning groups identify anchor tenants, increase involvement of state decision-makers, coordinate with utility personnel that approve resource procurement and create 20-year plans to achieve long-term carbon reduction goals.

Transmission Development (Chapter 3)

- **Two-thirds of the utilities interviewed say state policies or regulations impede development of interstate transmission.** Key areas of concern are local siting processes, inconsistent siting standards across borders and cost recovery risk. PUCs and provincial energy ministries cited the following hurdles: demonstration for a given state that a line is needed and will serve the public interest, lack of eminent domain authority, multiple uncoordinated approvals required by various levels of government and cost recovery processes.
- **Most PUCs find it difficult to approve a line sized beyond the definable future needs of their retail customers and to meet the needs of transmission customers with signed service agreements.** Statutory or regulatory changes may be needed to overcome barriers in transmission permitting and cost recovery processes to allow for right-sizing – building some level of transmission in advance of need to account for long-term demand, develop WREZ hubs and minimize the need for additional transmission corridors and associated environmental disruption.
- **While utilities and regulators were nearly universal in their support of the open season approach to amass financial support for transmission projects, it likely is insufficient to develop long interstate lines to WREZ hubs.** The chicken and egg problem remains: Generators will not make financial commitments for transmission absent a power purchase agreement with utilities, which will not sign such agreements absent transmission assurance.
- Many jurisdictions have express policies to develop facilities for export for economic development purposes. However, **the framework for reviewing the public purpose of a proposed transmission line for siting and cost recovery in most states does not address the economic benefit to the state of exporting resources.**
- **Most utilities said the institutional structure in place in the West is adequate, or can be adapted, to successfully develop transmission to WREZ hubs.** However, some utilities believe institutional and legislative changes are needed, including regional coordination of market functions and a clear long-term signal on environmental priorities.

Coordinated Resource Procurement (Chapter 4)

- **Some utilities believe cooperation may be required to develop resources in distant WREZ hubs and associated transmission.**
- **Utilities generally favor joint development and ownership over joint solicitations or coordinating separate solicitations. Most utility regulators are supportive of pursuing any of these approaches.**
- Many utilities pointed out that **regulations for resource planning and procurement do not anticipate joint or coordinated solicitations** and believe changes would be required to accommodate these approaches.

- **Transmission has greater potential for cooperation than renewable resource procurement, according to many utilities.**
- **Most utilities feel comfortable with the general concept of coordinated resource procurement if there's a shared need** – for example, to spread cost and risk, to share excess capacity, to comply with renewable resource mandates, to meet load and to support system reliability. **At the same time, utilities prefer to develop renewable resource projects independently given typical sizes and modular construction.** Exceptions to this view are where utility partnership reduces risk exposure and helps reach critical mass for economic development and operation, as may be the case for concentrated solar power and geothermal projects. New technologies such as wave energy also pose risk that may best be shared across a group of utilities.
- Beyond shared needs, utilities say **concrete commitments for coordinated resource procurement require a framework for developing renewable resources for export to distant load centers, and in some cases stricter renewable energy standards or carbon regulation.**
- **A number of factors affect whether utilities will partner with one another**, including proximity to each other's service areas, to the targeted resource area and to available transmission from the resource area; availability of local resources that dampens interest in more distant resources; similar ownership structure and management philosophy; mutual membership in an association or subregional planning group; a history of cooperation between the utilities; utility size; and similarities or differences in regulatory requirements.
- **Regulators are largely supportive of cooperative utility projects**, particularly to spread cost and risk across multiple parties and to aid in construction of transmission lines that cross jurisdictions. They see no major barriers to coordinating procurement across utilities, at least to align the timing of separate utility requests for proposals (RFPs) for the same resource locations.
- **Timing may be a significant issue for coordinated resource procurement**, including aligning resource planning and procurement cycles – especially with a utility in another state – and the lag between resource solicitations and transmission development.

Market Mechanisms to Aid Renewable Resource Development (Chapter 5)

- **Nearly all government officials interviewed for this report expressed support for increased trading of renewable energy credits**[2] for RPS compliance, in order to reduce the amount of transmission that needs to be built and the associated cost. However, they noted restrictions on this practice today and the difficulty in changing them. Some states raised concern that their native resources may lose out to cheaper resources elsewhere or that transmission constraints would strand renewable energy, which would be displaced by more expensive resources.
- While **regulators generally support steps to reduce the cost to consumers of integrating variable wind and solar generation (e.g., intra-hour transmission scheduling and generation dispatch)**, they want to know the specific costs and benefits for the utilities serving *their* customers. For any market mechanism that functions at a subregional or regional level, regulators also want to understand the potential implications of the choice of market operator.

[2] Renewable energy credits, also called renewable credits (or certificates), represent the environmental and other non-energy attributes of one megawatt-hour of electricity from a renewable energy generating unit. "Tradable" (or "unbundled") credits represent only the renewable and environmental attributes, sold separately from the underlying energy resource. Definitions of these attributes, including any emissions reductions, vary by state.

Recommendations
Following are recommendations based on these findings for consideration by states, provinces and regional bodies:

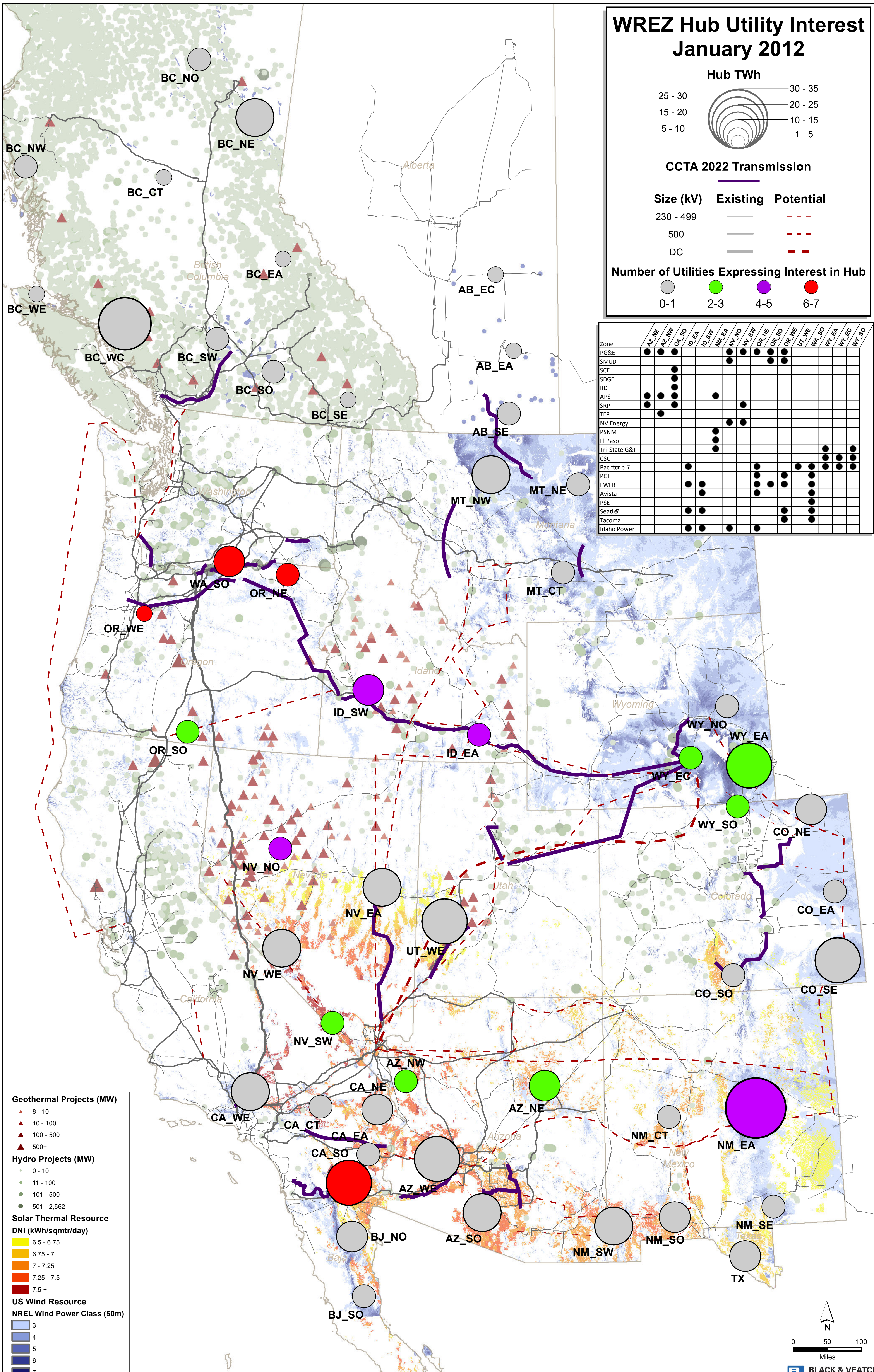
1. WGA should host trial discussion groups of utilities and regulators in 2012 to explore resource development and interstate transmission for WREZ hubs of common interest to utilities whose service areas jointly encompass multiple states, particularly where transmission is not available and where planned transmission is at risk. The goal is a comprehensive approach to developing these zones and identified transmission corridors. Other stakeholders should receive reports on the discussions and be brought into the process as it progresses. Transmission planning work by the Western Electricity Coordinating Council (WECC) and its Environmental Data Task Force and the Western Governors' Wildlife Council should be considered in the WREZ discussion groups, including potential transmission alternatives and configurations for long-term planning scenarios that consider environmental and cultural resources.
2. The Resource Planners Forum hosted by WECC and the Western Interstate Energy Board (WIEB) in 2012 should discuss potential changes in resource planning and procurement processes to facilitate joint development and other forms of coordinated procurement among utilities.
3. Regarding evaluation of WREZ hubs and transmission in local, subregional and regional planning:
    a. States and provinces should require utilities operating in their jurisdiction to evaluate WREZ resources and associated transmission in resource planning and procurement processes, including potential advantages and disadvantages of acquiring higher quality but more distant WREZ resources. States and provinces also should evaluate ways to improve the connection between long-term resource planning, transmission planning and resource procurement.
    b. States and provinces should request subregional planning groups to evaluate transmission alternatives to WREZ hubs of common interest among member transmission developers and involve state and provincial decision-makers in these discussions. Some subregional planning groups already have taken steps in this direction. For example, Northern Tier Transmission Group (NTTG) studied four scenarios with high levels of renewable resources in quality wind areas in Wyoming and Montana for its 2010-2011 transmission plan. NTTG determined that additional transmission, beyond the foundational lines, would be needed to accommodate such resources.[3]
    c. In future study cycles, WECC should build on the resource relocation cases for its 10-Year Regional Transmission Plan for 2020 to evaluate regional transmission alternatives to access geographically dispersed WREZ resources interconnection-wide. Longer-term transmission plans should consider the potential for higher renewable energy standards and more stringent air pollutant regulations.
4. Western governors and legislators should discuss options for harmonizing renewable energy credits that qualify for state renewable energy requirements, including reciprocity approaches for buying and selling power as well as renewable energy credits among neighboring jurisdictions, and potential cost reductions and economic development benefits for participating states.

[3] *See* NTTG's 2010-2011 Biennial Transmission Plan for the 2020 study year: http://nttg.biz/site/index.php?option=com_docman&task=cat_view&gid=308&Itemid=31. NTTG studied four scenarios with high levels of generation in high-quality wind areas: 3,000 MW in Montana, Wyoming, or both and 6,000 MW in Wyoming. The study assumed the additional renewable resources served markets in the Southwest and California. In the NTTG plan, see Chapter 6 for scenario cases and Appendix 3 for the list of transmission projects tested.

5. The Committee for Regional Electric Power Cooperation (CREPC) and the State-Provincial Steering Committee (SPSC) should explore the interaction of utility resource and procurement processes with subregional and regional transmission planning, particularly in light of FERC Order 1000 which requires each transmission provider to consider needs driven by public policy requirements in both local and "regional" planning. Such work should include evaluation of modeling tools to optimize selection of wind and solar sites to increase energy output, minimize output variability and foster increased power trading among states.
6. WGA should foster coordinated siting and permitting of transmission lines among all affected federal and state agencies and tribes. Cooperation on siting and permitting would support coordinated resource procurement and transmission development. Further, WGA should use the approaches and data developed by the Western Governors' Wildlife Council and WECC's Environmental Data Task Force to facilitate early coordination during the transmission planning phase to reduce the risk of serious problems with environmental and cultural issues arising during the transmission siting and permitting phase.
7. CREPC should consider whether to advocate for FERC transmission incentives for interstate lines that access renewable resources from regional renewable energy zones designated through a stakeholder-driven process in areas with low environmental conflicts.
8. CREPC and subregional planning groups should evaluate options for mitigating pancaked transmission charges. CREPC could begin exploring this issue at its spring 2012 meeting, inviting utility transmission managers and other experts to participate in a panel on this subject.
9. SPSC and CREPC should continue to explore ways to improve utilization of the existing transmission system in order to reduce the need for new lines to deliver energy from WREZ hubs to loads. The SPSC's planned 2012 workshop on advanced transmission technology could explore this topic.
10. CREPC should serve as a forum to vet ideas for increasing system flexibility – through demand-side measures, market mechanisms, operational changes, optimized siting of wind and solar resources, and new technologies – in order to mitigate growing concerns about integrating variable resources that may dampen renewable energy development overall.
11. Regional transmission expansion planning studies should further examine scenarios where transmission freed-up due to changes in resource mix and power plant operation could help deliver energy from WREZ hubs to load centers in ways that minimize output variability, reducing the need for new transmission facilities and fossil-fuel generation. Subregional planning groups should consider similar scenarios, as well as factors that affect repurposing transmission lines for delivering variable energy resources.
12. States and provinces should consider potential changes to cost recovery statutes in order to facilitate interstate transmission lines for renewable resources that provide long-term economic and reliability benefits for retail electric consumers and encourage efficient build-out of the regional grid.[4]

[4] For example, *see* Section 37-2-114 in Wyoming House Bill 111 (**http://legisweb.state.wy.us/statutes/statutes.aspx?file=titles/Title37/Title37.htm),** Kansas Statute 66-1247 (**http://kansasstatutes.lesterama.org/Chapter_66/Article_12/66-1247.html**) and Minnesota Statutes 216B.243, Subdivision 3 (**https://www.revisor.mn.gov/statutes/?id=216b.243**).

Recommendations	Entities				
	States and provinces	**CREPC**	**SPSC**	**WGA/ WIEB**	**WECC/ Subregional Planning Groups**
1. Host trial discussion groups of utilities and regulators to explore resource development and interstate transmission for WREZ hubs of common interest				X	
2. Discuss at Utility Resource Planners Forums potential changes in resource planning and procurement processes to facilitate joint development and other forms of coordinated utility procurement				X	
3a. Require utilities to evaluate WREZ resources and associated transmission in resource planning and procurement processes	X				
3b. Request subregional planning groups to evaluate transmission alternatives to WREZ hubs of common interest among member transmission developers and involve state and provincial decision-makers in these discussions	X				
3c. Build on the resource relocation cases for the 2020 regional transmission plan to evaluate regional transmission alternatives to access geographically dispersed WREZ resources interconnection-wide					X
4. Discuss options for harmonizing renewable energy credits that qualify for state renewable energy requirements, including reciprocity approaches for neighboring jurisdictions, and potential benefits for participants	X			X	
5. Explore the interaction of utility resource and procurement processes with subregional and regional transmission planning, particularly in light of FERC Order 1000 which requires each transmission provider to consider needs driven by public policy requirements in local and "regional" planning		X	X		
6. Foster coordinated siting and permitting of transmission lines among all affected federal and state agencies and tribes				X	
7. Consider whether to advocate for FERC transmission incentives for interstate lines that access renewable resources from regional renewable energy zones designated through a stakeholder-driven process		X			
8. Evaluate options for mitigating pancaked transmission charges		X			X
9. Continue to explore ways to improve utilization of the existing transmission system in order to reduce the need for new lines to deliver energy from WREZ hubs to loads		X	X		
10. Serve as a forum to vet ideas for increasing system flexibility – through demand-side measures, market mechanisms, operational changes, optimized siting of wind and solar resources, and new technologies – in order to mitigate growing concerns about integrating variable resources that may dampen renewable energy development overall		X			
11. Further examine in regional and subregional transmission planning studies where transmission freed-up due to changes in resource mix and power plant operation could help deliver energy from WREZ hubs to load centers; in subregional studies consider factors that affect repurposing transmission lines for delivering variable energy resources			X		X
12. Consider changes to cost recovery statutes to facilitate interstate lines for renewable resources that provide long-term benefits for retail consumers and encourage efficient build-out of the grid	X				



Zone	AZ_NE	AZ_NW	CA_SO	ID_EA	ID_SW	NM_EA	NV_NO	NV_SW	OR_NE	OR_SO	OR_WE	UT_WE	WA_SO	WY_EA	WY_EC	WY_SO
PG&E	●	●	●				●	●	●	●	●					
SMUD							●			●	●					
SCE			●													
SDGE			●													
IID			●													
APS	●	●	●			●										
SRP	●		●					●								
TEP		●														
NV Energy							●	●								
PSNM						●										
El Paso						●										
Tri-State G&T						●								●		●
CSU														●	●	●
PacifiCorp				●					●			●	●	●	●	●
PGE									●		●		●			
EWEB				●	●				●	●	●		●			
Avista					●				●				●			
PSE													●			
Seattle				●	●						●		●			
Tacoma											●		●			
Idaho Power				●	●		●		●							

WREZ WECC Interest in Zones 11 x 17 v2.mxd | C.Holmgren | 02/09/2012

Introduction

WGA established the WREZ initiative in 2008 on the heels of its Clean and Diversified Energy Initiative, which identified 30,000 megawatts (MW) of renewable and other clean energy resources in the region that could be developed by 2015 – and lack of transmission as a key obstacle.[5]

The U.S. Department of Energy funded the first two phases of the WREZ initiative in 2008 and 2009. Working with a technical advisory group and stakeholder-developed criteria, analysts identified 95,000 MW of high quality, developable wind in 53 hubs throughout the West.[6] Each hub has enough high-quality resources within 100 miles of its geographic center to justify a high-capacity transmission line (≥500 kV AC).[7]

An earlier WREZ report summarized results of the first phase of this initiative, including mapping hubs with the potential for large-scale development of renewable resources.[8] The maps show resources by class (for wind and solar) or relative scale (for hydro and geothermal), as well as exclusions for land deemed undevelopable or environmentally sensitive. Additional screens that balance renewable energy and transmission development with protection of wildlife and crucial habitat are needed to refine these areas. Such work is now underway for regional transmission expansion planning.

This report presents findings from utility-specific WREZ model[9] results and telephone interviews with 25 Western utilities,[10] PUCs in each of the Western states, and the energy ministries of Alberta and British Columbia, with additional information provided for context. Interviews were conducted from December 2010 to May 2011. The survey questions are in Appendix A. The interviews sought to:

- Identify WREZ hubs of greatest interest to utilities and reasons why, along with potential utility partners for developing these areas and associated transmission
- Assess ways to develop areas of common interest
- Determine potential obstacles and solutions
- Define key issues and trends in resource planning and procurement
- Identify major drivers in utility selection of renewable energy projects
- Understand how planned transmission projects may affect where utilities acquire renewable resources
- Benefit from lessons learned in past efforts in joint development
- Gain insights into ways subregional planning groups may assist in WREZ development
- Learn how utilities are considering potential environmental regulations and renewable energy standards in resource and transmission planning

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[5] Including energy efficiency, solar, wind, geothermal, biomass, clean coal technologies and advanced natural gas technologies. *See* http://www.westgov.org/component/joomdoc/doc_download/90-clean-energy-a-strong-economy-and-a-healthy-environment.

[6] *See* centerfold map. Zoom-in map at http://www.westgov.org/wieb/meetings/crepcsprg2011/briefing/present/utility/WREZMap.pdf.

[7] 1,500 MW of solar or wind, or 500 MW of biomass, geothermal or hydropower generating capacity.

[8] WGA, *Western Renewable Energy Zones, Phase 1 Report – Mapping Concentrated, High Quality Resources to Meet Demand in the Western Interconnection's Distant Markets*, June 2009, http://www.westgov.org/component/joomdoc/doc_download/5-western-renewable-energy-zones--phase-1-report.

[9] The public domain WREZ model and supporting information can be downloaded at http://www.westgov.org/rtep/220-wrez-transmission-model-page.

[10] Two sets of interviews were conducted with each utility: 1) resource planners and procurement managers and 2) regulatory/ government affairs and transmission managers.

- Survey practices for adding flexibility to utility systems to integrate variable energy resources
- Glean perspectives on market mechanisms that may reduce costs of meeting renewable energy goals and better use existing transmission capacity
- Gather recommendations for next steps in the WREZ process
- Identify additional electricity topics ripe for regional discussions

The report is organized into six chapters:

- Chapter 1 describes WREZ modeling tools, compares WREZ hubs the model finds to be most economic for each utility with the utilities' actual preferences (Tables 4 and 5), explains inconsistencies and highlights WREZ hubs of interest to multiple states (Table 6). The chapter also summarizes two studies pointing toward WREZ resources that may be most economic from a regional point of view under various scenarios.
- Chapter 2 provides an overview of resource planning and procurement requirements and utility views on resource planning and acquisition.
- Chapter 3 discusses issues in transmission planning and development.
- Chapter 4 summarizes views and issues related to coordinated development of WREZ hubs – joint resource or transmission development, joint or coordinated resource solicitations, and other possible approaches. Also presented are potential roles for subregional planning groups and subregional planning for renewable resources. The chapter concludes with potential partners identified by utilities for resource procurement and transmission (Table 11).
- Chapter 5 summarizes perspectives on regional market mechanisms to support development of higher levels of renewable resources in the West.
- Chapter 6 discusses possible next steps for the WREZ initiative and issues of interest for regional discussions.

Western Electric Industry Structure

The Western Interconnection includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of 14 Western states. WECC is the regional entity designated by the North American Electric Reliability Corporation for coordinating and promoting bulk electric system reliability in the interconnection. WECC also coordinates the operating and planning activities of its members. Some 38 balancing authorities[11] *operate grid systems within the interconnection. See Figure 1.*

Only Alberta and a portion of California have organized power markets.[12] *Elsewhere, the Western power system is dominated by vertically integrated utilities that determine what resources to acquire and rely on bilateral agreements for buying and selling power. State or provincial utility commissions oversee the regulated utilities.*[13]

Much of the Western U.S. is federal land,[14] *creating a powerful effect on siting of energy and transmission facilities. Two federal power marketing agencies – Bonneville Power Administration (BPA) and Western Area Power Administration (WAPA) – also exert significant influence as they market power primarily from federal hydroelectric dams and integrate and deliver electricity from both federal and non-federal generating projects. BPA operates and maintains about three-fourths of the high-voltage transmission in its service territory, which includes Idaho, Oregon, Washington, western Montana and small parts of eastern Montana, California, Nevada, Utah and Wyoming. WAPA serves a 15-state region in the Central and Western U.S. WAPA owns and maintains more than 10 percent of the transmission lines in the Western Interconnection.*

Outside of Alberta, long-term utility resource and procurement plans govern what resources are developed. Transmission planning also occurs at the utility level, as well as at the subregional level and interconnection-wide through WECC.

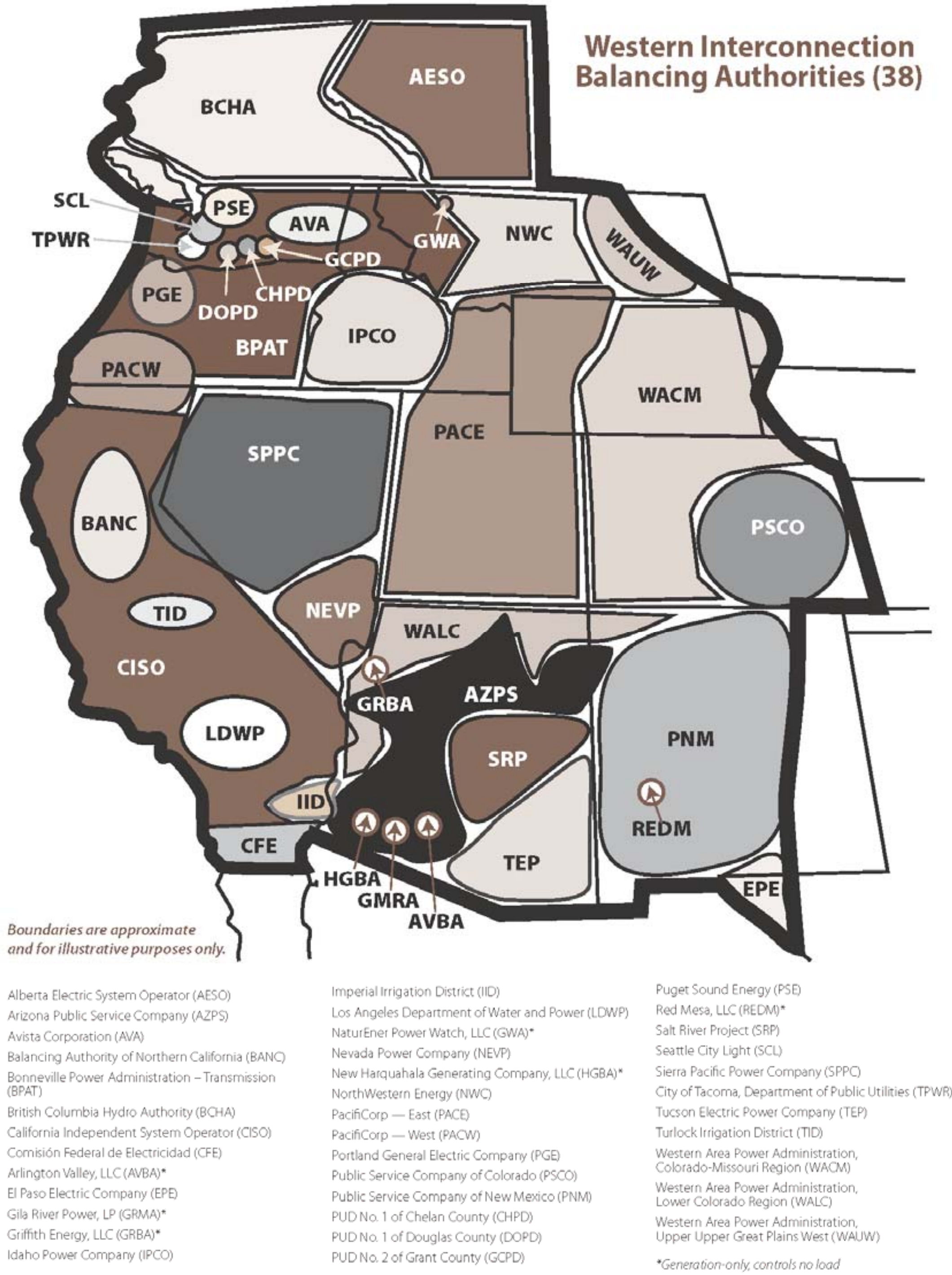
[11] "The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time." Glossary of Terms Used in NERC Reliability Standards, April 20, 2010.

[12] "Organized power markets" refers to power markets with an Independent System Operator (ISO) or Regional Transmission Organization (RTO) that operates a regional energy market.

[13] State-regulated utilities include investor-owned utilities – private companies financed by a combination of shareholder equity and bondholder debt – and, in some jurisdictions, selected consumer-owned utilities such as electric cooperatives.

[14] *See* National Atlas of the United States of America, Federal Lands and Indian Reservations, http://www.nationalatlas.gov/printable/images/pdf/fedlands/fedlands3.pdf.

Figure 1. Balancing Authorities in the Western Interconnection[15]



[15] WECC, http://www.wecc.biz/library/WECC%20Documents/Publications/Balancing%20Authorities.pdf.

Chapter 1. Utilities' Preferred Renewable Energy Zones

This chapter describes WREZ modeling tools, identifies WREZ hubs selected by the WREZ model as most economic for each utility, and compares the results with the utilities' actual preferences, as stated in the WGA interviews. Next is a listing of WREZ hubs of interest across utilities that together serve multiple jurisdictions – a potential focus for future WREZ work. The chapter wraps up with summaries of two studies pointing toward economic renewable resources in the Western Interconnection: 1) least-cost selection of WREZ resources under alternative future scenarios and 2) renewable resource relocation alternatives analyzed for WECC's 10-Year Regional Transmission Plan.

Renewable Energy Scenario Used for WREZ Model

Identifying renewable energy areas of interest to multiple utilities, particularly across multiple jurisdictions, is a key step in identifying WREZ hubs that states and provinces may wish to focus attention on for resource and transmission development. As a conversation-starter, the 25 utilities interviewed for this report received a customized analysis indicating which WREZ hubs, and resources within those hubs, may be most economic for the utility.[16] *For consistency across utilities and to show a deep resource stack, the analysis used a single scenario in which the utility meets 33 percent of its expected energy needs in 2030 with renewable resources. The intent was to stimulate long-term thinking about potential resource needs and associated transmission requirements 10 and 20 years into the future. Utilities were asked to identify WREZ hubs of greatest interest and, when applicable, why they are not interested in areas identified by the WREZ model as most economic for the utility.*

1.1. WREZ Modeling Tools

Two Excel-based modeling tools support the WREZ initiative. The Generation and Transmission (G&T) Model allows users to evaluate the delivered cost of power from each WREZ hub to any of 20 load centers. The Peer Analysis Tool allows users to create a supply curve of renewable resources in all WREZ hubs for any load center.[17]

The WREZ model calculates the adjusted delivered cost of energy (in dollars per megawatt-hour) of each type of resource in a WREZ hub – the *value* of the resource to the load zone, including energy and capacity benefits. See Figure 2. Users can change many of the assumptions in the model for consistency with their own assumptions.

A work group developed the busbar data for the WREZ G&T model – the levelized cost of energy including capital costs, operation and maintenance costs, fuel costs, heat rate (for biomass), incentives, net plant output, gen-tie costs, capacity factor, economic life, discount rate, inflation and financing costs.[18] Following is summary information on capital, transmission and integration costs, as well as a description of how energy and capacity value was determined for each resource.

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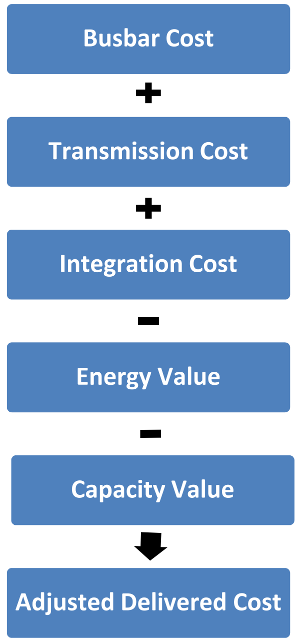
[16] Links to individual utility WREZ modeling results at http://www.westgov.org/component/joomdoc/doc_download/1397-wrez-utility-model-results-2011.

[17] *See* http://www.westgov.org/index.php?option=com_content&view=article&catid=102%3Ainitiatives&id=220%3Awrez-transmission-model-page&Itemid=81.

[18] For a discussion of resources and the Qualified Resource Area identification process, *see* Ryan Pletka and Josh Finn, Black & Veatch Corp., *Western Renewable Energy Zones, Phase 1: QRA Identification Technical Report*, prepared for National Renewable Energy Laboratory, October 2009, http://www.nrel.gov/docs/fy10osti/46877.pdf.

[18] For a complete set of assumptions for the WREZ model, *see* http://www.westgov.org/wga/initiatives/wrez/gtm/documents/GTM%20V%202.0%20Method%20Assumptions.pdf.

Figure 2. Adjusted Delivered Cost of Energy



Capital Costs

Table 1 shows the capital cost estimates used in the utility-specific WREZ modeling conducted for this report, compared to estimates for WECC's 2010 Transmission Expansion Planning Policy Committee (TEPPC) Study Program – with updated solar photovoltaic (PV) values – and long-term procurement plans for California investor-owned utilities.

Table 1. Capital Cost Estimates ($/kW)[19]

Resource Type	**2010 TEPPC Study Cycle**	**California Long-Term Procurement Plans**	**WREZ Initiative**
Biomass	$4,250	$4,529	$3,400 to $6,000
Geothermal	$5,500	$5,155	$4,143 to $13,404
Hydro - Small	$3,300	$3,960	$652 to $3,680 (depending on size)
Wind-Onshore	$2,350	$2,350	$2,200
Solar Thermal – Trough, No Storage	$5,350	$5,300	$5,100 (wet-cooled) $5,300 (dry-cooled)
Solar Thermal – Trough With Storage	$7,500	$7,500	$7,400 (wet-cooled) $7,750 (dry-cooled)
Solar PV – Fixed Tilt	$4,000	$4,000	$3,800
Solar PV - Tracking	$4,700	$4,700	$4,500

[19] Figures include engineering, procurement and construction costs plus all other owner's costs, such as AFUDC, gen-tie, permitting, legal and financing. TEPPC and California values from Arne Olson and Andres Pacheco, E3, "Capital Cost Estimates," presentation to TEPPC Technical Advisory Subcommittee, March 29, 2011, http://www.wecc.biz/committees/BOD/TEPPC/TAS/04132011/Lists/Minutes/1/E3_TEPPC_ResourceCapCost_Update_2011-03-29.pdf. WREZ values from Pletka and Finn, October 2009; costs for wind, solar thermal and solar PV updated in January 2011.

Utility Reservations About the WREZ Analysis and Approach
Important qualifiers for perspectives presented in this report are some utilities' disagreement with the assumptions used in the WREZ model, as well as the overall thesis of the WREZ initiative – that high-quality renewable resources will be developed in locations remote from load centers.

Some utilities said a 33 percent by 2030 renewable resources target is not likely for their state, and therefore the need to develop remote WREZ hubs is diminished. While this level of non-hydro renewable resources is far more aggressive for most areas in the Western Interconnection than current acquisition plans and statutory or regulatory requirements, some states already mandate similar targets, at least for investor-owned utilities. Breakthroughs and cost reductions for renewable energy technologies and changes in renewable energy requirements and environmental regulations also may nudge renewable resource procurement to higher levels in the future than anticipated today.

Some utilities also disagree with the model-assigned capacity value for wind, instead assuming that wind resources provide no capacity value, at least in certain regions. In addition, several utilities raised concerns about the lack of solar resources in the model results. These issues are discussed in this chapter.

Another overarching comment expressed in the utility interviews is that WGA could better assist the region by seeking consensus among Western states on definitions of renewable resources (but not necessarily resource targets) for renewable energy standards. There was surprisingly strong support for this position, in unsolicited comments and in response to a question directed at this issue.

Transmission and Integration Costs
Transmission costs are the levelized costs of delivering energy from the resource to the load area, including losses. All resources are assumed to require new transmission. Cost estimates are based on a 500 kV single-circuit AC line[20] operating at 50 percent utilization.

Integration costs are the indirect operation cost to the transmission system to accommodate generation from the renewable resource on the grid. Utility-specific analyses conducted for this report used the following figures:

- Wind - $5/MWh
- Solar thermal - $2.50/MWh
- Solar PV - $2.50/MWh

Energy and Capacity Value
Energy value represents the value to the load zone of the hourly output of the resource. Black & Veatch developed the energy values based on a 2015 market forecast ($2009) using the ProMod production cost model.

Capacity value is based on the resource's contribution to reserve margin requirements. The capacity value represents the avoided expense of purchasing an alternative source of capacity – the fixed costs of a natural gas-fired, simple-cycle combustion turbine. The on-peak capacity credit for each potential project is its average expected operation during the 10 percent of the hours in the year with the highest load. Figure 3 shows an example calculation.

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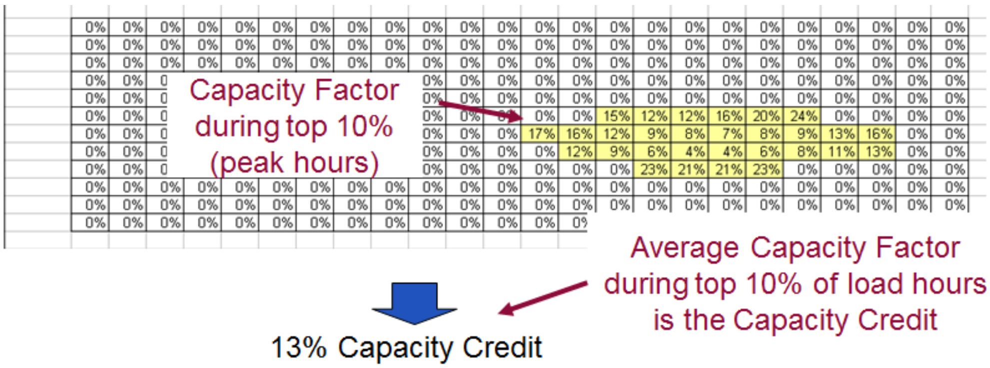
[20] DC lines are a lower cost alternative for delivering large volumes of energy over long distances. Using DC lines to access remote renewable resources could materially change the results of the utility supply curves developed in support of this report.

Figure 3. Example Capacity Value Calculation for WREZ Model



Capacity Credit	13%
Resource Reserve Margin Cost: CT	\$114/kW-yr
Project Capacity Factor	35%

$$\text{Capacity Value (\$/MWh)} = \frac{\text{Capacity Credit x Resource Reserve Margin Cost (\$/kW-yr)}}{\text{[Project Capacity Factor x (8760 hours in a year/1000)]}}$$

(13%) x (\$114/kW-yr) / [(35%) x (8,760 hours per year / 1,000 kW/MW)] = \$5/MWh

Updates From Earlier WREZ Analyses

Following are modifications to the WREZ model for the analysis performed in support of this report.

1. Wind capacity factors were updated and are higher than in earlier model runs.

Wind power class	Class 3	Class 4	Class 5	Class 6	Class 7
Current capacity factor	0.32	0.36	0.39	0.42	0.46
Old capacity factor	0.28	0.31	0.35	0.40	0.42

2. The model reflects reductions in wind turbine prices and improved performance. Wind capital costs were reduced from \$2,300/kW to \$2,200/kW.

3. Wind resources are now binned by resource class instead of broad cost ranges, so the model can pick individual wind classes. The model first selects the highest-class wind resources in a WREZ hub; lower class wind is added further down in the supply curve once the high-class resources have been exhausted.

The above changes tend to benefit wind to the detriment of solar.

4. The current analysis assumes transmission utilization is 50 percent for all the lines. This change benefited both wind and solar resources. Previously, utilization was based on the resource capacity factor – making transmission utilization (unrealistically) high for geothermal and biomass.

WREZ Model Limitations
Like all models, the WREZ model has limitations. First, it only selects resources in designated WREZ hubs and ignores resources that may be closer to the utility's service area. That's inherent in the nature of the model; it was created to demonstrate the relative economics of areas with high-quality resources in sufficient amounts to support development of high-capacity transmission lines (≥500 kV AC).

Second, it assumes no constraints on location of resources due to RPS geographic eligibility requirements or renewable energy credit multipliers for in-state resources. In effect, the model optimizes economics and ignores policies that jurisdictions created largely for economic development purposes. Third, it assumes all WREZ resources need new transmission – an overly conservative assumption that overstates the cost of some resources.

In addition, while there has not been an explicit assessment of the model's margin of error, it is expected to be similar to the values for the California Renewable Energy Transmission Initiative model. In that case, the standard error (one standard deviation from the mean value) ranged from $15 per MWh to $21 per MWh, depending on the resource.[21]

Importantly, the difference in adjusted delivered cost of energy for wind vs. solar resources as determined by the WREZ model is within the margin of error for some combinations of WREZ hubs and load centers. That means that where the model does not select solar resources for a particular utility, solar may in fact be an economic choice. That's the case notwithstanding the margin of error, because the model develops cost curves, not prices utilities see in actual practice.

While not a limitation of the model, the default assumption for transmission is 500 kV single-circuit AC lines. That assumption was used in the WREZ modeling in support of this report. DC lines are a lower cost alternative for delivering large volumes of energy over long distances. Using DC lines to access remote renewable resources could materially change the results of the utility supply curves developed for this report. As with several other variables in the WREZ model, users can change the type of transmission line to DC to see how the results change.

1.2. Utility-Specific WREZ Model Results

Black & Veatch performed customized analysis using the WREZ model for each of the 25 utilities interviewed for this report under a scenario in which the utility meets 33 percent of its expected demand in 2030 with renewable energy.[22] The results indicate renewable resources that may be most economic for the utility by type, class and WREZ hub. Results are sorted by adjusted delivered cost of energy, with itemized costs (busbar, transmission and integration) and energy and capacity benefits. Table 2 shows an example of the detailed resource results each utility received. Table 3 shows the summary of findings grouped by WREZ hub for the example utility.

The results package also included a rough cost comparison with local solar and wind resources, which are not analyzed in the WREZ model. Figure 4 is an example of the information provided to each utility.

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[21] Communication with Ryan Pletka, Black & Veatch, March 30, 2011. Geothermal was at the low end of the range; solar PV at the high end.
[22] To calculate demand for renewable resources in 2030, analysts simply multiplied this percentage times the utility's load forecast for that year (based on public information).

Table 2. Most Economic WREZ Resources – Example: Public Service of Colorado[23]

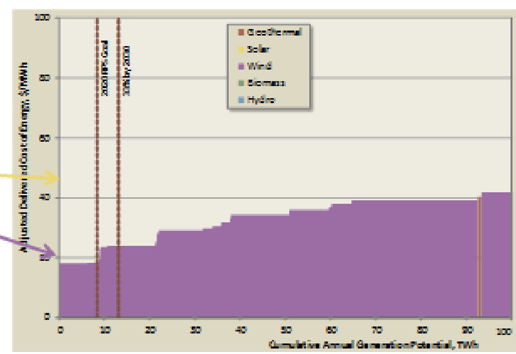
				Generation				Adjusted Delivered Cost of Energy $/MWh					
					Cumulative*								
Rank	Type	Location	Capacity, MW	Resource, GWh/yr	GWh/yr	% of 2030 load	Busbar Cost	Tx Cost with Losses	Integration Cost	Energy Value	Capacity Value	Total
1	Wind Class 7	Wyoming South	102.7	0.4	0	<1%	$61	$8	$5	($55)	($6)	**$13**
2	Wind Class 7	Wyoming East	1,536.0	6,189.3	6,190	16%	$61	$13	$5	($55)	($6)	**$18**
3	Wind Class 6	Wyoming South	740.1	2,723.0	8,913	23%	$67	$8	$5	($55)	($6)	**$18**
4	Wind Class 7	Colorado South	4.6	18.5	8,931	23%	$61	$17	$5	($56)	($8)	**$20**
5	Wind Class 6	Colorado Northeast	3.8	14.0	8,945	23%	$67	$13	$5	($55)	($7)	**$23**
6	Wind Class 5	Wyoming South	481.6	1,645.3	10,591	27%	$72	$8	$5	($55)	($6)	**$24**
7	Wind Class 6	Wyoming East	2,839.6	10,447.3	21,038	54%	$67	$13	$5	($55)	($6)	**$24**

Table 3. Most Economic WREZ Hubs – Example: Public Service of Colorado[24]

	Capacity by Resource Type, MW									
Area	Biomass	Solar	Geothermal	Hydro	Wind Class 3	Wind Class 4	Wind Class 5+	Total Capacity, MW	Total Generation, GWh/yr	Energy Weighted Adjusted Cost ($/MWh)*
Colorado South							5	5	19	20
Wyoming South							1324	1324	4369	20
Wyoming East							4376	4376	16637	22
Colorado Northeast							4	4	14	23

Figure 4. Economics of Local vs. WREZ Resources – Example: Public Service of Colorado

Generic Comparative Local Resource	Adjusted Delivered Cost of Energy, $/MWh					
	Busbar Cost	Tx Cost	Int. Cost	Energy Value	Capacity Value	Total Without Tx Cost
Solar PV	$136	Varies	$2.5	($61)	($33)	$44
Wind Class 3	$88	Varies	$5.0	($56)	($8)	$30
Wind Class 4	$78	Varies	$5.0	($56)	($8)	$20
Wind Class 5	-	Varies	$5.0	-	-	-
Wind Class 6	-	Varies	$5.0	-	-	-
Wind Class 7	-	Varies	$5.0	-	-	-



A detailed map of each of the top WREZ hubs for the utility shows the renewable resources in the area, by class for wind and solar and by relative size (MW) for other resources, as well as lands excluded from consideration due to environmental restrictions (e.g., wilderness areas) or other land use constraints (urban areas). The maps also show utility service area boundaries and transmission lines – existing (230 kV and higher), "foundational" and "potential."[25] Figure 5 is a map with potential resources for an example WREZ hub.

[23] The "Cumulative" columns are running totals. The cumulative generation column (GWh/yr) is the running total of resources identified as most economic. For example, the cumulative generation column for Colorado South includes resources in that hub as well as resources in higher-ranking hubs – in this case, certain wind resources in Wyoming. The next column shows the corresponding percentage of 2030 load for all these resources.
[24] Energy Weighted Adjusted Cost shows the adjusted delivered cost of energy weighted by the energy share of each resource in the WREZ hub. Only resources identified as most economic toward meeting a 33 percent by 2030 renewable energy target are included in the calculation.
[25] *Foundational* lines are those included in a subregional planning group's 10-year transmission plan and assumed to have a high probability of being built in the next 10 years. These lines were input assumptions for WECC's 10-year Regional

The utility also received a chart showing the output profile of the resource from the largest WREZ hub (by generation) selected by the model as economic for the utility under a 33 percent by 2030 RPS scenario. Figure 6 is an example.   The model was run independently for each utility, using the same potential resources for all WREZ hubs. To provide a consistent basis to compare utilities, the analysis made simplifying assumptions as described above. The model results may differ from the utilities' current resource priorities. In addition, the model does not reflect the utility's existing resources.

Figure 5. Wyoming East Resources With Utility Service Area Boundaries and Transmission Lines

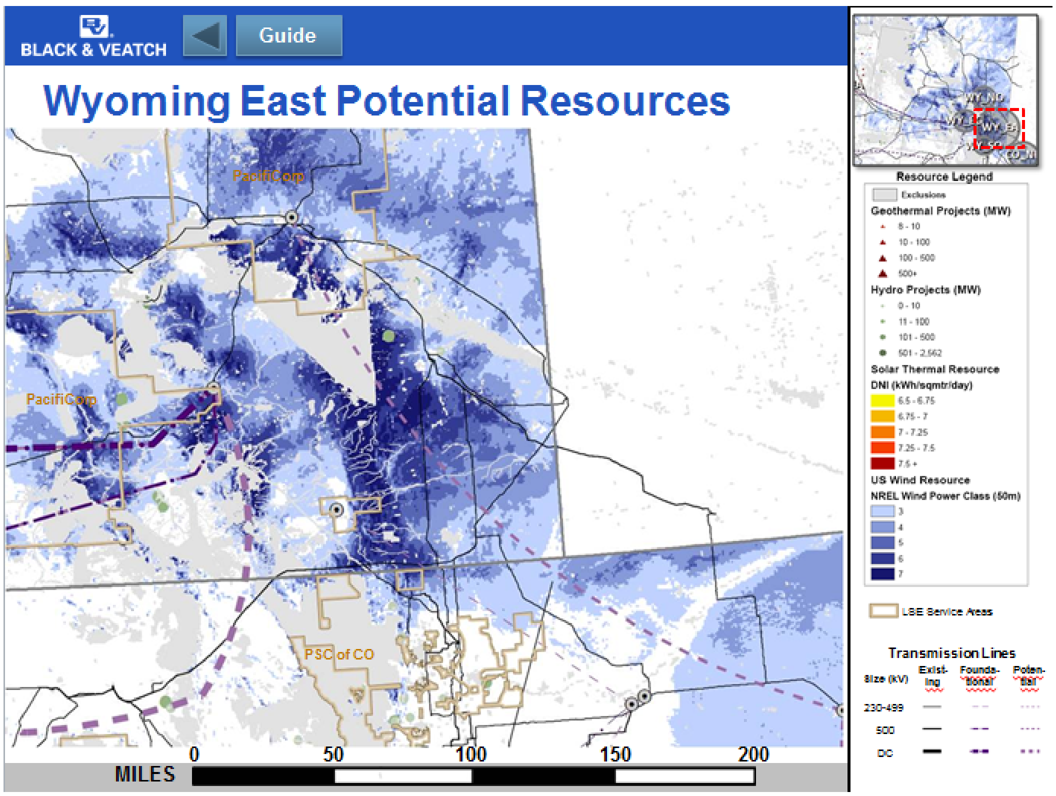
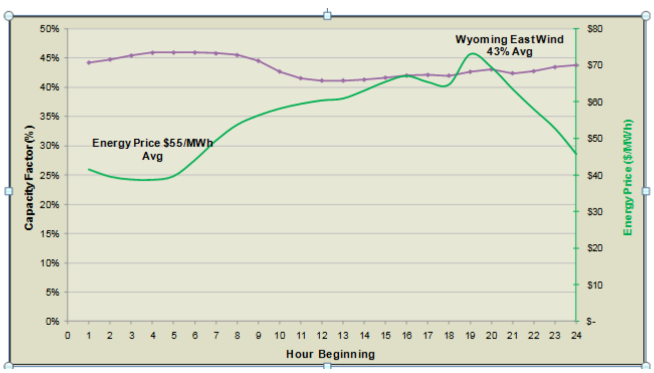


Figure 6. Annual Average Hourly Profile for Wyoming East Wind



Transmission Expansion Plan for 2020. *Potential* lines are projects that a subregional planning group has identified in a 10-year transmission plan but do not meet the foundational project criteria. WECC uses potential lines when selecting additional or alternative facilities for transmission planning studies.

1.3. Preferred WREZ Hubs Identified By Utilities

Consistency With WREZ Model Results

Utility interviews asked whether the top WREZ hubs (and resources within the hubs) identified by the WREZ model as most economic for the utility are consistent with its long-term resource plans. Table 4 lists WREZ hubs of greatest interest to each utility, according to the WGA interviews. Table 5 compares WREZ hubs selected by the model vs. WREZ hubs identified by utilities.

In many cases, the model results are not in sync with the utilities' preferred renewable energy areas. Besides limiting resource selection to WREZ hubs and ignoring limitations in state renewable energy requirements on resource location, there are many other reasons. First, as discussed above, the difference in adjusted delivered cost of energy for wind vs. solar for some WREZ hub/load zone combinations is within the margin of error of the model. Further, the WREZ resource supply curves indicate relative *cost*, not price. For example, the model does not capture current pricing that solar developers are offering utilities, and that pricing may reflect some risk-taking on future prices for solar modules in order to make bids as attractive as possible. Therefore, the model results do not track California and Southwest utility plans for solar.

Second, some top WREZ hubs identified by the model have not shown up in utility IRP modeling or in bids utilities have received through resource solicitations. Conversely, utilities have received attractive bids in areas outside the top-identified WREZ hubs – in areas outside of WREZ hubs that are within or closer to the utility service area. Third, where tradable renewable energy credits are allowed, utilities are acquiring resources not selected by the model – e.g., resources in Idaho.[26] The following section lists other reasons for the differences between utilities' preferred renewable energy areas and WREZ model results.

Reasons Cited for Preferred WREZ Hubs

Of the many factors utilities identified as affecting where the utilities plan to acquire renewable resources, the most common response is that *all* their decisions are driven by cost, whether directly (the cost of the renewable resource) or indirectly (e.g., the transmission cost to deliver the resource to load). That's despite framing the interview question to seek out factors other than cost: "Besides cost, why is your utility focusing on the resource locations you identified and not on other locations?" However, the cost driver is tempered by perceived risk of cost recovery, along with the following other responses to this question:

- Current or future availability of transmission
- Portfolio/geographic diversification – to mitigate swings in generation output or to comply with regulatory requirements
- Requirements in statute or regulations, including whether the resource is in-state
- Proximity of resource to load
- Integration concerns – load shape and intermittency
- Quality, reliability or maturity of resource
- Risk factors – concerns about permitting or completing projects timely
- Abundance of resource

[26] Lawrence Berkeley National Laboratory analyzed an unbundled renewable energy credit scenario using the WREZ model. *See* the discussion later in this chapter.

Availability of transmission to deliver energy to load centers was the most cited driver other than cost in choosing resource location. Utilities typically raised issues about the cost and complexity of building new transmission facilities, particularly siting and logistics associated with regulatory requirements that vary by state. Utilities suggested that devising some form of uniform, streamlined process for siting, approving and building transmission across state lines would be extremely helpful.[27]

Utilities also widely cited portfolio diversity as an important driver. They are seeking to procure a diverse array of resources to balance geographically concentrated wind and solar resources with their overall energy mix.

Several utilities noted RPS requirements that give preferential treatment to native resources – for example, a multiplier for renewable energy credits for in-state projects. Utilities recommended that such preferences be eliminated in order to create an even playing field where cost and the market would signal more efficient investments.

Many utilities voiced concern about the quality, reliability and maturity of renewable resources. These concerns shed light on the risk involved with procuring resources sometimes many years in advance of their expected on-line date. Will the project developer finish the project on time and within budget? Will the generation profile of the resource be as expected? Will technologies develop and mature as anticipated? Each of these concerns embodies a risk that is difficult to estimate but which has financial implications for the utilities.

[27] The New England States Committee on Electricity recently announced the formation of the New England Interstate Transmission Siting Collaborative to consider, and implement as appropriate, ways to increase coordination of states' siting processes required for interstate transmission facilities in the region. Meeting with New England transmission owners and developers on areas where improved coordination efforts would deliver regional value is among the initial steps. *See* http://www.nescoe.com/uploads/Interstate_Siting_Collaborative.pdf.

Table 4. Utility-Identified WREZ Hubs of Greatest Interest

WREZ Hub	BC Hydro	Northwestern	PG&E	SMUD	LADWP*	SCE	SDGE	Imperial Irrigation	APS	SRP	TEP	NV Energy*	PSNM	El Paso	Tri State	CSU	PSCO	PacifiCorp UT	PacifiCorp OR	PacifiCorp WA	PGE	EWEB[28]	Avista	PSE	Seattle	Tacoma	Idaho Power
Arizona Northeast			X						X	X																	
Arizona Northwest			X						X		X																
Arizona South			X																								
Arizona West			X					X																			
California Central			X	X		X	X																				
California East			X	X		X																					
California Northeast			X	X		X																					
California South			X			X	X	X	X	X																	
California West			X	X		X	X																				
Colorado East															X	X	X										
Colorado Northeast																X	X										
Colorado Southeast																X	X										
Colorado South																X	X										
Idaho East																		X	X	X		X			X		X
Idaho Southwest																						X	X		X		X
Montana Central		X																									
Montana Northeast																											
Montana Northwest																							X				
New Mexico Central																											
New Mexico East									X				X	X	X												
New Mexico Southeast														X													
New Mexico South																											
New Mexico Southwest																											
Nevada East			X																								
Nevada North			X	X																							X
Nevada Southwest			X							X																	
Nevada West			X																								

* Utility declined to identify WREZ hubs of particular interest.

[28] When EWEB needs more resources, it will be looking for resources in the Northwest other than wind, which produce power during the fall and winter.

WREZ Hub	BC Hydro	Northwestern	PG&E	SMUD	LADWP*	SCE	SDGE	Imperial Irrigation	APS	SRP	TEP	NV Energy*	PSNM	El Paso	Tri State	CSU	PSCO	PacifiCorp UT	PacifiCorp OR	PacifiCorp WA	PGE	EWEB[28]	Avista	PSE	Seattle	Tacoma	Idaho Power
Oregon Northeast			X															X	X	X	X	X	X				X
Oregon South			X	X																		X					
Oregon West			X	X																	X	X			X	X	
Texas																											
Utah West																		X	X	X							
Washington South																		X	X	X	X	X	X	X	X	X	
Wyoming East															X	X		X	X	X							
Wyoming East Central																X		X	X	X							
Wyoming North																X											
Wyoming South															X	X		X	X	X							
Alberta East																											
Alberta East Central																											
Alberta North																											
Alberta Southeast																											
British Columbia Central	X																										
British Columbia East	X																										
British Columbia Northeast	X																										
British Columbia North	X																										
British Columbia Northwest	X																										
British Columbia Southeast	X																										
British Columbia South	X																										
British Columbia Southwest	X																										
British Columbia W. Central	X																										
British Columbia West	X																										
Baja North							X																				
Baja South							X																				

Table 5. Utilities' Preferred Renewable Energy Zones – Model Results vs. Interview Findings[29]

Utility	WREZ Model Results (Most Economic WREZ Hubs - 33% by 2030 RPS Scenario[30])	Interview With Utility Resource Planning/Procurement (Actual Interest, Resource Plans, Acquisitions)
Arizona Public Service	• Geothermal – Cheapest in UT_WE; also good (and plentiful) in CA_SO • Wind – BJ_NO, CA_WE, CA_SO and AZ_NE	• Solar – Pursuing local solar • Geothermal – CA_SO and NM_EA • Wind – Primarily in northern Arizona where there is existing transmission capacity
Avista	• Wind – WA_SO, MT_CT and OR_NE	• WREZ hubs in Washington, Oregon, Idaho and Montana, depending on transmission costs and transmission constraints
BC Hydro	• Geothermal – OR_WE and BC_WC • Wind – OR_WE, OR_SO, WA_SO, OR_NE, MT_CT and MT_NW	• British Columbia hubs; no consideration of resources outside of BC
Colorado Springs	• Wind – WY_SO and WY_EA	• Wind – Preference for wind from Colorado because of in-state multiplier for RPS; also consider WY wind
El Paso Electric	• Wind – TX and NM_SE	• Wind – Pursuing wind in NM_SE and NM_EA
Eugene Water & Electric Board	• Wind – OR_WE and WA_SO	• When EWEB needs more resources, it will be looking for resources in the Northwest other than wind that produce power during fall and winter
Idaho Power	• Wind – WY_EC	• Geothermal – ID_SW and ID_EA • Wind – ID_SW, ID_EA and OR_NE • Solar – ID_SW • Biomass – ID_EA
Imperial Irrigation District	• Wind – CA_SO, CA_WE and BJ_NO	• Planning to focus primarily on renewable resources in local territory (geothermal, wind, biomass and solar) and considering other compliance methods, including sources outside of IID territory, to minimize the cost impact
Los Angeles Department of Water & Power	• Geothermal – Cheapest in UT_WE; plentiful but more expensive in NV_NO and CA_SO • Wind – CA_WE, CA_NE, BJ_NO, CA_CT and CA_SO	• Utility declined to identify specific zones of interest; focusing on wind resources
Northwestern Energy	• Wind – MT_CT	• Rich local resources (wind particularly) make extra-jurisdictional resource acquisition unnecessary; to the extent resources are needed, utility is looking east of the Continental Divide
NV Energy	• Geothermal – UT_WE and NV_NO • Wind – UT_WE, CA_NE, CA_WE, AZ_NW, NV_SW and CA_CT	• Model-identified WREZ hubs generally are consistent with the utility's viewpoint. Long-term contracts tend to gravitate toward in-state resources, but the utility continues to seek offers from out-of-state projects.[31]

[29] *See* centerfold map for location of WREZ hubs identified in this table.
[30] Table excludes WREZ hubs with small amounts (<50 MW) of economic resources under this modeling scenario.
[31] Utility declined to identify specific WREZ hubs.

Utility	WREZ Model Results (Most Economic WREZ Hubs - 33% by 2030 RPS Scenario[30])	Interview With Utility Resource Planning/Procurement (Actual Interest, Resource Plans, Acquisitions)
Pacific Gas & Electric	• Geothermal – NV_NO, OR_WE, OR_SO, UT_WE and ID_EA • Wind – Best in CA_WE, OR_WE and OR_SO; also good in CA_SO & CT and BJ_NO • Biomass – OR_SO	• Solar – Signing many contracts for utility-scale projects in CA_EA, CA_CT, NV and AZ • Geothermal – CA_NO, NV and OR • Wind - California and Pacific Northwest
PacifiCorp - Utah[32]	• Geothermal – ID_EA, UT_WE and NV_NO • Wind – ID_EA, UT_WE, WY_EA & CT, MT_CT and WY_SO	• Geothermal – A PacifiCorp-commissioned study of commercially viable sites within 100 miles of an interconnection to the utility's grid identified eight potential sites in CA, OR, UT and ID.[33] • Wind – Primary areas: OR_NE, WA_SO, WY_EA & CT and WY_SO; secondary areas: ID_EA and UT_WE
PacifiCorp - Oregon	• Geothermal – OR_WE • Wind – OR_WE, OR_SO, OR_NE and WA_SO	
PacifiCorp - Washington	• Wind – OR_NE, WA_SO and MT_CT	
Portland General Electric	• Geothermal – OR_WE • Wind – OR_WE, OR_SO, OR_NE and WA_SO	• Geothermal – OR_WE • Wind – OR_WE, OR_NE and WA_SO
Public Service of Colorado	• Wind – WY_SO and WY_EA	• Wind – CO_SO, CO_NE, CO_EA and CO_SE
Public Service of New Mexico	• Wind – NM_EA	• Wind – NM_EA; not pursuing resources outside of New Mexico
Puget Sound Energy	• Geothermal – OR_WE • Wind – OR_WE, WA_SO, MT_CT and OR_SO	• PSE has not analyzed a 33% RPS scenario and has no plans to do so • Geothermal – Not seeing OR resources developed • Wind – Focused on WA_SO; OR_SO has no transmission so would be costly, and MT transmission is too expensive and does not qualify for WA RPS unless delivered in real-time[34]
Sacramento Municipal Utility District	• Geothermal – NV_NO, OR_WE and OR_SO • Wind – CA_WE and OR_SO	• Geothermal – CA_NE, NV_NO, NV_WE, OR_WE and OR_SO • Wind – CA_NE, CA_WE, NV_WE and OR_SO • Also looking to acquire biogas (methane) and local solar (depending on the pace of technology maturation)
Salt River Project	• Geothermal – UT_WE and CA_SO • Wind – AZ_NE, BJ_NO, CA_WE and CA_SO	• Solar – pursuing local solar • Geothermal – CA_SO and NM_EA • Wind – Primarily in AZ_NO, where there is existing transmission capacity

[32] Black & Veatch performed modeling separately for three states served by PacifiCorp – Utah, Oregon and Washington. Such modeling is not intended to represent how PacifiCorp in practice meets RPS requirements in its various jurisdictions.

[33] Modeling for PacifiCorp's 2011 IRP selected geothermal resources for every portfolio analyzed. However, the company's preferred portfolio excludes geothermal resources due to lack of state legislation and regulatory pre-approval mechanisms for recovery of dry-hole drilling costs. *See* PacifiCorp's 2011 IRP, March 31, 2011, at 7: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2011IRP/2011IRP-MainDocFinal_Vol1-FINAL.pdf.

[34] See Washington RCW 19.285.030(10), which in part defines RPS-eligible resources as "Electricity from a generation facility powered by a renewable resource other than fresh water that commences operation after March 31, 1999, where: (i) The facility is located in the Pacific Northwest; or (ii) the electricity from the facility is delivered into Washington state on a real-time basis without shaping, storage, or integration services."

Utility	WREZ Model Results (Most Economic WREZ Hubs - 33% by 2030 RPS Scenario[30])	Interview With Utility Resource Planning/Procurement (Actual Interest, Resource Plans, Acquisitions)
San Diego Gas & Electric	• Geothermal – CA_SO • Wind – CA_WE, BJ_NO, BJ_SO, CA_CT and CA_SO	• Geothermal – CA_SO • Wind – CA_WE, BJ_NO, BJ_SO, CA_CT and CA_SO • Particularly interested in resources in CA_SO, CA_WE and CA_CT
Seattle City Light	• Geothermal – OR_WE • Wind – OR_WE and WA_SO	• Geothermal – OR_WE • Wind – OR_WE and WA_SO • Also looking to Idaho for wind, geothermal and solar • Washington RPS requirements effectively limit where utility can acquire resources
Southern California Edison	• Solar – CA_WE, CA_SO, CA_CT and CA_EA • Geothermal – NV_NO, CA_SO, UT_WE and NV_WE • Wind – BJ_NO, CA_NE, CA_WE, CA_SO, BJ_SO, AZ_NW, NV_SW, CA_CT, AZ_NE, UT_WE, NV_WE, CA_EA and WY_EC • Biomass – CA_WE	• Preference for renewable resources delivered to California (but resource could be located in-state or out of state), but decisions will be driven by value considerations subject to regulatory constraints
Tacoma Power	• Geothermal – OR_WE • Wind – WA_SO and OR_WE	• Geothermal – OR_WE • Wind – WA_SO and OR_WE
Tri-State	• Wind – WY_EA and WY_SO	• Wind – WY_EA and WY_SO • Generally – WY_SE, CO_EA and NM_EA
Tucson Electric Power	• Geothermal – UT_WE • Wind – CA_SO, NM_EA, AZ_NE, BJ_NO and CA_WE	• Solar – Aggressively pursuing local solar[35] • Wind – AZ_NW; AZ_NE has too many constraints to be viable; projecting out 5-10 years, TEP is not currently looking outside AZ for resource acquisition

Comparison With WREZ Model Results - Montana
According to the WREZ model results, PacifiCorp, Avista, Puget Sound Energy, BC Hydro and NorthWestern should all be interested in wind (class 5+) in the Montana Central WREZ hub. Following are the reasons the utilities gave for the lack of development and at least near-term interest in this area:

- Renewable resource developers need long-term contracts with utilities to get transmission built from this area to load centers. But utilities are not interested in resources unless transmission already exists or there is a high degree of certainty for its timely completion.
- The transmission cost, including pancaking of rates across lines on which the resource travels, makes it tough for utilities to look this far away.
- The utility's IRP model does not pick resources in Montana.

However, some utilities pointed out that new transmission lines from Montana, as well as siting and other development issues in other areas, may change their views.

Comparison With WREZ Model Results - Wyoming
According to the model results, PacifiCorp and Idaho Power should be highly interested in developing the Wyoming East-Central WREZ hub. The Wyoming North and Wyoming South hubs also are economic

[35] Tuscon Electric Power is primarily focused on solar development within its distribution system, mostly because of the lack of transmission to its load center.

for PacifiCorp, according to the model results. PacifiCorp stated that these hubs match up with its resource planning. While the company does not expect to issue its next RFP for utility-scale renewable resources until 2017,[36] the preferred portfolio in its recently filed IRP includes 800 MW of incremental renewable resources in Wyoming by 2020, plus 1,300 MW of additional Wyoming wind capacity by 2030.[37]

While Idaho Power has looked at Wyoming wind in its resource planning process, the company views southern Idaho wind as more economic considering transmission costs. While the company has no RPS obligation in the state of Idaho, wind and other renewable resources are part of the company's IRP strategy to balance cost, risk and environmental concerns. Meantime, the obligation to purchase energy and capacity from Qualifying Facilities under the federal Public Utility Regulatory Policies Act (PURPA) has hindered the company's plans to acquire wind resources through competitive solicitations.[38]

The WREZ model also indicates that Public Service of Colorado (PSCo) and Colorado Springs Utilities should be interested in wind (class 5+) in both the Wyoming East and Wyoming South WREZ hubs. In fact, Table 3 earlier in this report shows that the WREZ model selected only miniscule amounts of wind outside Wyoming for PSCo under a 33 percent by 2030 RPS scenario. However, PSCo has not found Wyoming wind competitive with Colorado wind in resource solicitations to date. It is important to note that Colorado's RPS has a 1.25 multiplier for in-state wind facilities – a hurdle that is difficult for out-of-state projects to overcome. Colorado Springs Utilities expressed interest in wind from the Wyoming hubs identified by the WREZ model, as well as wind in Colorado, especially given the in-state multiplier.

1.4. WREZ Hubs of Interest to Utilities Across Multiple Jurisdictions

Table 6 shows WREZ hubs of interest to multiple utilities that together serve retail customers in more than one state. The table also shows whether transmission capacity is available on existing lines, or would be made available if planned lines are completed, to deliver power from the WREZ hub to the utility's service area. Transmission projects are planned for most of the 16 WREZ hubs listed, though it is unlikely that all of these projects will be built. WGA will consider WREZ hubs of interest across multiple jurisdictions, as well as transmission availability and transmission plans for these zones, in determining the next steps for the WREZ initiative.

[36] PacifiCorp forecasts its RPS positions by year in its 2011 IRP at 11: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2011IRP/2011IRP-MainDocFinal_Vol1-FINAL.pdf.
[37] *See* Table ES.3 – 2011 IRP Preferred Portfolio, PacifiCorp 2011 IRP, at 8.
[38] PURPA, passed in 1978, is codified in 16 U.S.C. § 824a-3. For wind and solar, the Idaho PUC has at least temporarily returned to the federal minimum threshold – 100 kW – for projects eligible for standard PURPA rates and contracts. *See* Order Nos. 32176 and 32212 in Case No. GNR-E-I0-04, http://www.puc.idaho.gov/internet/cases/summary/GNRE1004.html. *Also see* Case No. GNR-E-11-03, http://www.puc.idaho.gov/internet/cases/summary/GNRE1103.html.

Table 6. WREZ Hubs of Interest to Multiple Jurisdictions

Zone	Utilities Expressing Interest in Zone	States Served[39]	Available or Planned Transmission From Zone to Utility Service Area?[40]
AZ_NE	PG&E, APS, SRP	CA, AZ	**PG&E** – No **APS** – Available, High Plains Express (P) **SRP** – Available, High Plains Express (P)
AZ_NW	PG&E, APS, TEP	CA, AZ	**PG&E** – No **APS** – Available, C3ET (P), Tehachapi Upgrade (F) **TEP** – Available, Pinal Central-Tortolita (F)
CA_SO	PG&E, SCE, SDG&E, IID, APS, SRP	CA, AZ	**PG&E** – No **SCE** – Available, Blythe-Devers (F) **SDG&E** – Available, Sunrise (F) **IID** – Available, Sunrise (F) **APS** – Available, PV-NG#2 (F) **SRP** – Available, PV-NG#2 (F)
ID_EA	PacifiCorp, EWEB, Seattle, Idaho Power	OR, WA, ID, UT, WY, CA	**PacifiCorp** – Available, Gateway West Ph 1 (F), Gateway West Ph 2 (P), Hemingway-Boardman (F), Hemingway-Captain Jack (P) **EWEB** – Gateway West Ph 1 (F), Gateway West Ph 2 (P), Hemingway-Boardman (F), Cascade Crossing (F) **Seattle** – Available, Gateway West Ph 1 (F), Gateway West Ph 2 (P), Hemingway-Boardman (F), Cascade Crossing (F), I-5 Corridor (F), West McNary (F), Big Eddy-Knight (F) **Idaho Power** – Available, Gateway West Ph 1 (F)
ID_SW	EWEB, Avista, Seattle, Idaho Power	OR, WA, ID, UT, WY, CA	**EWEB** – Hemingway-Boardman (F), Cascade Crossing (F) **Avista** – Available, Gateway West Ph 1 (F), Gateway West Ph 2 (P) **Seattle** – Available, Hemingway-Boardman (F), Cascade Crossing (F), I-5 Corridor (F), West McNary (F), Big Eddy-Knight (F) **Idaho Power** – Available, Gateway West Ph 1 (F), Gateway West Ph 2 (P)
NM_EA	APS, PSNM, El Paso, Tri-State	AZ, NM, TX, CO	**APS** – SunZia (P), High Plains Express (P) **PSNM** – Limited Available **El Paso** – Available, SunZia (P), High Plains Express (P) **Tri-State** – Available, High Plains Express (P)
NV_NO	PG&E, SMUD, IPCo	CA, ID (NV[41])	**PG&E** – No **SMUD** – No **IPCo** – Chinook (P), Zephyr (P) **NV Energy** – SWIP South (F), SWIP North (P), Chinook (P)
NV_SW	PG&E, SRP	CA, AZ (NV)	**PG&E** – No **SRP** – TCP Northwest-Amargosa (F), TCP Harry Allen-Northwest (F), PV-Blythe (P) **NV Energy** - TCP Northwest-Amargosa (F), TCP Harry Allen – Northwest (F)

[39] All jurisdictions served by utilities expressing interest in the zone are listed. Not addressed here are state RPS locational or deliverability requirements or multi-state utility issues. For example, PacifiCorp serves retail customers in six states – Utah, Oregon, Washington, Wyoming, Idaho and California. However, not all jurisdictions participate in the multi-state agreement that allocates costs for resources that serve the system on an integrated basis.

[40] Transmission information from Black & Veatch, August 2011. "Available" indicates that some capacity remains on *existing* transmission lines to deliver power from the zone to the utility. "Foundational" (F) lines are those included in a subregional planning group's 10-year transmission plan and assumed to have a high probability of being built in the next 10 years. These lines were input assumptions for WECC's 10-Year Regional Transmission Plan for 2020. "Potential" (P) lines are projects identified in a subregional planning group's 10-year transmission plan that did not meet the foundational project criteria. WECC selected among these lines when testing additional or alternative transmission facilities. "No" indicates that new transmission, beyond the foundational and potential projects, would be needed to deliver energy from the zone to the utility service area.

[41] While NV Energy declined to identify zones of particular interest, the utility indicated that WREZ model-identified zones of interest generally are consistent with the utility's viewpoint. In addition, while the utility continues to seek offers from out-of-state projects, long-term contracts tend to gravitate toward in-state resources.

OR_NE	PG&E, PacifiCorp, PGE, EWEB, Avista, IPCo	OR, WA, ID, UT, WY, CA	**PG&E** – No **PacifiCorp** – Available, Gateway West Ph 1 (F), Gateway West Ph 2 (P), Gateway Central Ph 1 (F) **PGE** – Available, Hemingway-Boardman (F) **EWEB** – Available, Hemingway-Boardman (F) **Avista** – Available **IPCo** – Available, Hemingway-Boardman (F)
OR_SO	PG&E, SMUD, EWEB[42]	CA, OR	**PG&E** – Available **SMUD** – Available **EWEB** - Available
OR_WE	PG&E, SMUD, PGE, EWEB, Seattle, Tacoma	OR, WA, ID, UT, WY, CA	**PG&E** – No **SMUD** – No **PGE** - Available **EWEB** – Available **Seattle** – Available **Tacoma** - Available
UT_WE	PacifiCorp	OR, WA, ID, UT, WY, CA	**PacifiCorp** – Available, Hemingway-Boardman (F), Gateway West Ph 1 (F), Gateway West Ph 2 (P), Gateway Central Ph 1 (F), Gateway South Ph 1 (F), Gateway South Ph 2 (P), Transwest Express (P)
WA_SO	PacifiCorp, PGE, EWEB, Avista, PSE, Seattle, Tacoma	OR, WA, ID, UT, WY, CA	**PacifiCorp** – Available, Hemingway-Boardman (F), Gateway West Ph 1 (F), Gateway West Ph 2 (P) **PGE** – Available, Hemingway-Boardman (F) **EWEB** – Available, Hemingway-Boardman (F) **Avista** – Available **PSE** – Available **Seattle** – Available **Tacoma** – Available
WY_EA	Tri-State, CSU, PacifiCorp	CO, OR, WA, ID, UT, WY, CA	**Tri-State** – Limited Available **CSU** – Available, High Plains Express (P), Wyoming-Colorado Intertie (WCI) (P), Pawnee-Daniels Park (P) **PacifiCorp** – Available, Overland (P)
WY_EC	CSU, PacifiCorp	CO, OR, WA, ID, UT, WY, CA	**CSU** – High Plains Express (P), WCI (P), Pawnee-Daniels Park (P) **PacifiCorp** – Available, Overland (P)
WY_SO	Tri-State, CSU, PacifiCorp	CO, OR, WA, ID, UT, WY, CA	**Tri-State** – Limited Available **CSU** – Available, Waterton-Midway (F), Pawnee-Smoky Hill (F), WCI (P) **PacifiCorp** – Available, Gateway West Ph 1 (F), Gateway South Ph 1 (F), Gateway South Ph 2 (P)

[42] When EWEB needs more resources, it will look for resources in the Northwest other than wind that produce power during the fall and winter.

Least-Cost Selection of WREZ Hubs West-wide
In 2010, Lawrence Berkeley National Laboratory published its analysis of least-cost selection of WREZ resources West-wide under alternative future scenarios for meeting 33 percent of loads with renewable resources by 2029, including:[43]

- *Using 500 kV DC lines for transmission over 400 miles instead of single-circuit 500 kV lines*
- *Lower capital costs for wind*
- *Using tradable renewable energy credits*[44]

The model simulated competition for these resources, allocating WREZ resources to the load zone that would gain the most economic benefit from procuring the resource.[45]

Wind energy was the largest source of renewable energy procured across nearly all scenarios analyzed (38 percent to 65 percent of the total), with solar energy typically second (14 percent to 41 percent of the total). Solar exceeded wind, by a small margin, only when the cost of solar thermal technology was reduced relative to the other technologies. Not surprisingly, when the model assumes lower solar capital costs, limited transmission expansion and higher wind integration costs, it procures more solar energy. Depending on the scenario, load zones in the Southwest switched between wind and solar, with resulting changes in transmission expansion decisions.

The transmission investment required under scenarios in which each load zone must meet 33 percent of its load with delivered renewable energy from selected WREZ hubs was estimated at $22 billion to $34 billion. Although a few of the new transmission lines in the least-cost solution for each scenario were over 800 miles, most were relatively short, with average transmission distances ranging from 230 miles to 315 miles, depending on the scenario. Under a scenario where tradable renewable energy credits could be used to meet 50 percent of the renewable energy target, the required investment in transmission declined to $17 billion. Even at $17 billion to $34 billion, transmission costs represented just 10 percent to 19 percent of the total delivered cost of renewable energy.

1.5. WECC Transmission Planning Studies - Relocation of Renewable Resources

California accounts for the lion's share of incremental renewable resources needed in the West based on current RPS requirements. In support of its 2020 transmission plan, WECC analyzed potential cost savings and transmission needs for scenarios that substituted higher quality out-of-state resources for a portion of California-sited resources assumed in WECC's reference case.[46]

For the 2019 study year, WECC analyzed eight alternative resource locations for 12,000 gigawatt-hours (GWh) of California's incremental renewable resource need: Arizona/southern Nevada, northern

[43] Andrew Mills, Amol Phadke and Ryan Wiser, Lawrence Berkeley National Laboratory, *Exploration of Resource and Transmission Expansion Decisions in the Western Renewable Energy Zone Initiative*, February 2010, http://eetd.lbl.gov/EA/EMP/reports/lbnl-3077e.pdf. The analysis also looked at renewable energy targets of 12 percent and 25 percent.
[44] In the "limited" renewable energy credits scenario, a load zone could meet up to 33 percent of its annual energy needs with any one type of renewable technology and procure up to 50 percent renewable energy in total, selling excess renewable energy credits beyond the 33 percent simulated requirement.
[45] In reality, however, actual resources utilities procure depend on their ability to acquire resources before others, timing of required renewable energy targets, and flexibility to acquire resources in advance and bank renewable energy certificates.
[46] The WECC reference case relied on the California PUC's 2009 reference case for meeting a 33 percent RPS.

Nevada, Wyoming, Montana, New Mexico/southern Colorado, coastal Northwest, British Columbia and Alberta. That amount represents 12 percent of California's forecasted RPS requirement, with the resulting portfolio consisting of 74 percent in-state resources, compared to 86 percent in the reference case. The replacement resources were in lieu of the lowest-ranking resources in California renewable energy zones, based on commercial interest, resource quality and environmental factors.

For the 2020 study year, WECC analyzed two "aggressive" wind cases, replacing 25,000 GWh of the lowest-ranked renewable generation designated to serve California (including some out-of-state resources) with wind in Wyoming or Montana. WECC used the WREZ Peer Analysis Tool to identify the best locations for adding wind in these states. The resulting portfolio consisted of 58 percent California resources, compared to 77 percent in the 2020 reference case.

WECC analyzed transmission expansion alternatives in conjunction with these relocation cases, though the incremental transmission was not optimally sized for the capacity of the replacement resources. In addition, actual costs for generation and transmission may be different than assumed in these cases, as indicated by WECC's subsequent sensitivity analysis. Other factors also must be taken into account, including the risk of completing long-distance transmission projects and deliverability of the energy to load centers. Still, these studies point toward potential cost savings from accessing distant, high-quality renewable resources. Table 7 and Figures 7 and 8 illustrate potential savings for the 2019 study year cases (12,000 GWh of relocated resources). Table 8 shows potential savings for the 2020 study year cases (25,000 GWh of resources relocated to Montana or Wyoming).

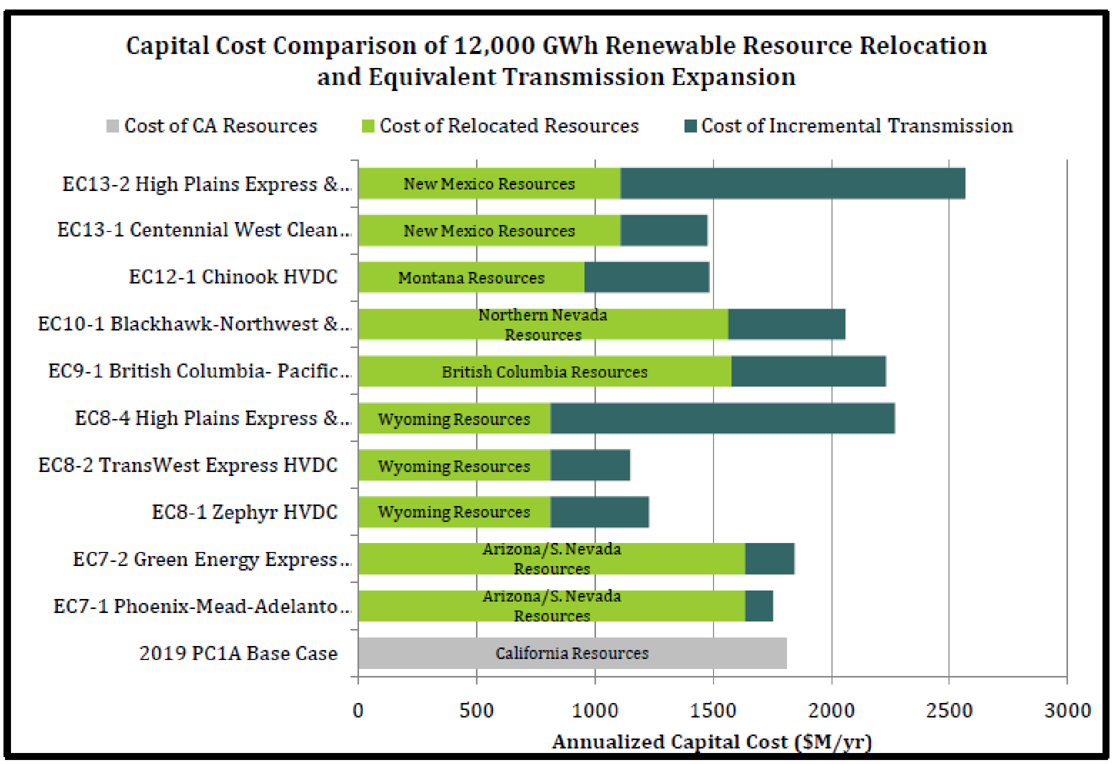
Potential capital cost savings are large. Even including system-wide production costs, savings can be significant. For example, relocating 25,000 GWh of resources to Wyoming and adding the TransWest Express line results in about a 45 percent reduction in capital costs and roughly $1.3 billion less in total costs, including production costs, in the year 2020 – about a 6 percent cost reduction overall.

Table 7. Comparison of Potentially Cost-Effective Resource Relocation Alternatives With Transmission Expansion – 2019 Study Year[47]
($M/year)

	2019 Wind and Transmission Expansion	Change in Resource Capital Cost	Transmission Capital Cost	Change in Production Cost	Annual Net Change	Resource and Transmission Capital Cost + Production Cost	Percent Change From PC1	Resource and Transmission Capital Cost Only	Percent Change in Resource and Transmission Capital Cost Only
EC13-1	Centennial West Clean Line	-700	369	11	-320	25440	-1.2%	1479	-18.3%
EC13-2	SunZia, High Plains Express	-700	1456	12	768	26528	3.0%	2566	41.8%
EC12-1	Chinook Project	-853	529	-17	-341	25419	-1.3%	1486	-17.9%
EC10-1	Blackhawk-Tesla and Blackhawk-Las Vegas	-245	495	-3	247	26007	1.0%	2060	13.8%
EC9-1	CNC DC Line	-231	654	-56	367	26127	1.4%	2233	23.4%
EC8-4	High Plains Express and SunZia	-997	1456	7	466	26226	1.8%	2269	25.4%
EC8-2	TransWest Express	-997	337	1	-659	25101	-2.6%	1150	-36.5%
EC8-1	Zephyr Project	-997	418	2	-577	25183	-2.2%	1231	-32.0%
EC7-2	Green Energy Express Phase 2&3	-172	207	-44	-9	25751	0.0%	1845	1.9%
EC7-1	Phoenix-Mead-Adelanto AC to DC Conversion	-172	116	-49	-105	25655	-0.4%	1754	-3.1%

2019 PC1 Base Case	Resource Capital Cost	Transmission Capital Cost	Production Cost	Total Cost
PC1	1810	0	23950	25760

Figure 7. Total Capital Cost of Resource Relocation With Equivalent Transmission Expansion[48]



[47] Adapted from Table 2, *WECC 10-Year Regional Transmission Plan Summary*, September 2011, http://www.wecc.biz/library/StudyReport/Wiki%20Pages/Home.aspx, and Table 71, *2019 Study Report – TEPPC 2010 Study Program*, September 2011, http://www.wecc.biz/library/StudyReport/Documents/2019%20Study%20Report.pdf, per communication with Heidi Pacini, WECC, January 2012.

[48] Figure 6, *TEPPC 2010 Study Program Report of Updated 2019 Studies*, June 2011, http://www.wecc.biz/library/StudyReport/Wiki%20Pages/Home.aspx.

Figure 8. Capital Cost Comparison of Potentially Cost-Effective Resource Relocation Alternatives With Large-Scale Transmission Expansion[49]

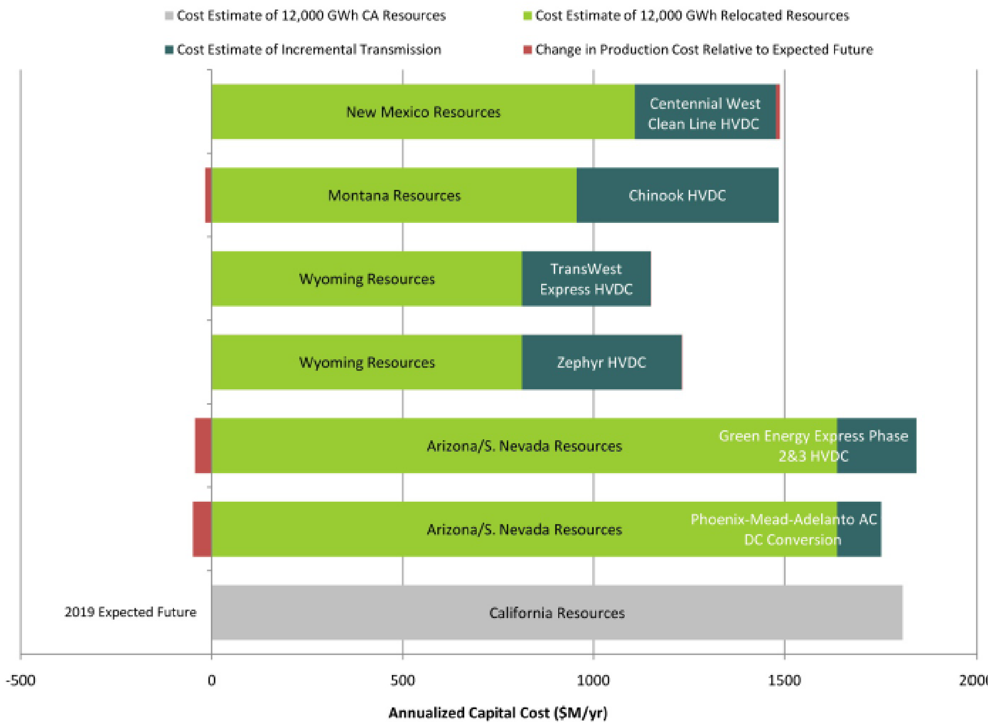


Table 8. Comparison of Potentially Cost-Effective Resource Relocation Alternatives With Transmission Expansion – 2020 Study Year[50]
($M/year)

2020 Aggressive MT Wind and Transmission Expansion	Change in Resource Capital Cost	Transmission Capital Cost	Change in Production Cost	Annual Net Change	Resource and Transmission Capital Cost + Production Cost	Percent Change From PC1	Resource and Transmission Capital Cost Only	Percent Change in Resource and Transmission Capital Cost Only
25,000 GWh Relocation to MT	-1291	0	1025	-266	21855	-1.2%	2641	-32.8%
plus Chinook Project, 3,000 MW	-1291	569	514	-208	21913	-0.9%	3210	-18.4%
plus MSTI & MT-NW Path-8 Upgrades, 2,200 MW	-1291	223	680	-388	21733	-1.8%	2864	-27.2%

2020 Aggressive WY Wind and Transmission Expansion	Change in Resource Capital Cost	Transmission Capital Cost	Change in Production Cost	Annual Net Change	Resource and Transmission Capital Cost + Production Cost	Percent Change From PC1	Resource and Transmission Capital Cost Only	Percent Change in Resource and Transmission Capital Cost Only
25,000 GWh Relocation to WY	-2096	0	530	-1566	20555	-7.1%	1836	-53.3%
plus SunZia and High Plains Express & Gateway West #2, 5,000 MW	-2096	1610	-27	-513	21608	-2.3%	3446	-12.4%
plus TransWest Express, 3,000 MW	-2096	337	450	-1309	20812	-5.9%	2173	-44.7%

2020 PC1 Base Case	Resource Capital Cost	Transmission Capital Cost	Production Cost	Total Cost
	3932	0	18189	22121

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49 Figure 11, *WECC 10-Year Regional Transmission Plan Summary*.
50 Adapted from Table 23 and Table 25, *2020 Study Report – TEPPC 2010 Study Program*, September 2011, http://www.wecc.biz/library/StudyReport/Documents/2020%20Study%20Report.pdf, per communication with Heidi Pacini, WECC, January 2012.

Chapter 2. Utility Resource Planning and Procurement

This chapter provides an overview of resource planning and procurement requirements and utility views on resource planning and acquisition, including:

- *Key issues and barriers to efficiency in these processes and recommendations for improvement*
- *Drivers for resource selection*
- *Specificity of resources sought*
- *Coordination of resource and transmission planning*
- *Comparing remote vs. local resources*
- *Distributed generation trends*
- *Potential effects of more stringent environmental and renewable energy standards*
- *Building flexibility into resource portfolios*

The chapter concludes with a discussion of cost recovery issues for renewable resources and associated transmission and recommended changes in cost recovery mechanisms to facilitate development of WREZ hubs. Appendix B provides links to each utility's most recent IRP and each jurisdiction's resource planning and procurement regulations. Also included are utility-by-utility summaries of these processes and current renewable resource solicitations.

2.1. State and Provincial Regulations on Resource Planning and Procurement

At the highest level, traditional cost of service regulations for utilities regulated by states and provinces are broad requirements governing resource acquisition. These regulations require rates to be just and reasonable, and facilities included in rates to be used and useful and in the public interest.[51]

Beyond that, most jurisdictions require utilities to engage in IRP or long-term procurement planning, where the utility may be able to request approval or acknowledgment of a preferred portfolio of resources considering cost, risk and uncertainty. In a couple of states, these processes authorize utilities to procure resources and ensure recovery of their prudently incurred costs.

Most jurisdictions also have competitive bidding and contracting requirements that affect resource procurement. These may be in the form of explicit requirements in statute[52] or PUC guidelines that are reviewed during the resource procurement process and at the time the utility requests cost recovery for resulting projects.[53]

Permitting for generation and transmission also strongly affects resource planning and procurement processes. Whether permitting takes place at the county or state level – and regardless of whether state authority resides at the PUC, another agency or an independent siting authority – the process requires a determination of whether the generation or transmission facilities are in the public interest, balancing

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[51] *See* Chapter 4.
[52] For example, *see* Nevada's requirements in NAC 704.8885 for factors considered in approving long-term renewable energy contracts and NAC 704.8887 for determination of whether the price is reasonable, http://www.leg.state.nv.us/register/2010Register/R064-10A.pdf. *Also see* Utah Code Section *54*-17-101 (Energy Resource Procurement Act), http://le.utah.gov/~code/TITLE54/54_17.htm.
[53] For example, see Oregon PUC's competitive bidding guidelines (Order No. 06-446): http://apps.puc.state.or.us/orders/2006ords/06-446.pdf.

environmental harm and societal benefits. There also may be standards requiring a demonstration of need.

In addition, some states have adopted aggressive energy efficiency policies that affect renewable resource planning and procurement to the extent they reduce retail sales that serve as the basis for RPS targets in the West. Distributed generation requirements in renewable energy standards also reduce the need for utility-scale renewable resources as well as transmission.

Utilities also acquire renewable resources through PURPA. To the extent state policies encourage development of PURPA Qualifying Facilities, they may drive significant renewable resource development in the state. Several Western utilities now have feed-in tariffs,[54] a new twist on the standard offers under PURPA.

Alberta's resource development landscape differs from other jurisdictions in the West. There is no centralized planning for energy, and utilities serve only as the supplier of last resort, procuring energy through short-term contracts.

State and Provincial Energy Policies

The biggest driver of renewable resource development in the U.S. is state renewable energy requirements that require utilities and other retail electric providers to supply specified amounts of their retail load with qualifying resources. Often, tradable renewable energy credits may be used to satisfy a portion of the requirement.[55] Nine of the 11 Western states have adopted renewable portfolio standards:

- *Arizona – 15 percent by 2025*
- *California – 33 percent by 2020*
- *Colorado - 30 percent (investor-owned utilities) or 10 percent by 2020 (co-ops, municipal utilities)*
- *Montana – 15 percent by 2015*
- *Nevada – 25 percent by 2025*[56]
- *New Mexico - 20 percent (investor-owned utilities) or 10 percent by 2020 (co-ops)*
- *Oregon - 25 percent (large utilities), 5 percent (smallest utilities) or 10 percent (others) by 2025*
- *Utah – 20 percent by 2025*
- *Washington – 15 percent by 2020*

RPS features that affect the types and locations of resources developed include geographic eligibility, delivery requirements and in-state preferences, limitations on use of tradable renewable energy credits, and requirements for solar and other types of distributed generation. Based on current requirements, California accounts for about two-thirds of incremental RPS-related demand in the West between 2010 and 2020. And like other states with an RPS, other than Oregon and Utah, California is expected to acquire about three-quarters of this generation from in-state resources.[57]

[54] *See* Chapter 3.
[55] *See* Ryan Wiser, Lawrence Berkeley National Laboratory, "The State of the Market: Update on the Implementation of U.S. Renewables Portfolio Standards," Renewable Energy Markets Conference, Nov. 16, 2011, http://renewableenergymarkets.com/docs/presentations/2011/Ryan%20Wiser.pdf.
[56] Energy efficiency may qualify for up to 25 percent of the requirement. *See* NRS 704.7821.2(2)(b).
[57] *WECC 10-Year Regional Transmission Plan Summary*, September 2011, http://www.wecc.biz/library/StudyReport/Wiki%20Pages/Home.aspx.

Greenhouse gas regulations are another driver for development of renewable resources. British Columbia has a carbon tax. Alberta requires facilities that exceed a threshold level of carbon emissions to pay a carbon tax or buy offsets. California adopted a cap on greenhouse gas emissions that went into effect in January 2012. And the three West Coast states have emissions performance standards that effectively preclude utilities from acquiring any new long-term coal resources without carbon capture and sequestration. In addition, the Western Climate Initiative is designing a regional carbon cap and trade system with initial participation by California and several Canadian provinces.

Many Western states also have a renewable energy zones process that identifies high-quality areas and ways to accelerate transmission to deliver resources to load centers. See Appendix C.

2.2. Utility Issues, Barriers and Recommendations

Utility resource planning and procurement personnel identified the following as the key issues they struggle with, particularly as they relate to renewable resources:

- Resource variability, reliability and integration
- Acquiring transmission and meeting deliverability requirements
- Interconnecting generating facilities
- Resource costs
- Financing – tax policies and uncertainty in financial and credit markets
- Cost recovery uncertainty
- Changing legislative and regulatory policies
- Project viability – high attrition rate for renewable projects due to project manager inexperience, collapse of financing or inability to acquire permits[58]
- Environmental impact
- Siting
- Lack of resource diversity
- Impact on energy markets of large amounts of wind resources

Utilities also noted several barriers to efficient planning and procurement for renewable resources. First, is the lack of consistent, stable policies, including differing RPS requirements among states, changes in an individual state's RPS policies, and the failure to establish stable federal tax credits for renewable resources. Second, many utilities noted the difficulty in siting both renewable energy projects and associated transmission. The challenge is particularly difficult when the resource is remote from loads it is intended to serve and the resource and load are in different states. Third, nearly all utilities noted the sheer complexity and length of planning and procurement processes involving public input, regulatory review, technical issues and significant financial investments.

[58] One utility noted the perverse impact this has on planning for transmission. Because each renewable energy project must petition for interconnection to the grid, there is the perception that there will be a need for many millions of dollars in transmission upgrades. However, because so many of the projects do not materialize, those upgrades are unnecessary. This dynamic obscures the real cost of transmission and hampers the planning process. Another utility described what it views as a particularly precarious situation: The utility is responsible for meeting a variety of regulatory requirements for renewable energy. However, because the state regulator prefers independently owned generating resources, the utility must rely on third parties with high failure rates for project completion.

Utilities also mentioned difficulties synchronizing short timelines for developing renewable energy projects with long regulatory processes for resource planning, procurement and, in some locales, pre-construction approval.

One or more utilities suggested the following changes in federal or state regulations to improve efficiency of renewable resource planning and procurement. Generally the recommendations are aimed at reducing the complexity and variability of regulatory processes and providing certainty for project financing:

- *Establish firm federal tax policy so markets know what to expect and to facilitate long-term resource planning.* Utilities said that as long as federal tax credit policy regarding renewable projects remains unclear, projects will struggle to acquire financing and long-term utility planning will suffer. The solution utilities propose is for the federal government to set clear, long-term tax credit policies.

- *Relax FERC rules restricting communication between utility transmission and merchant departments.* FERC rules prohibiting the utility's merchant personnel from talking with its transmission personnel unnecessarily complicate and delay resource planning and procurement processes, according to some utilities. Relaxing those rules would simplify and quicken the processes.

- *Amend procedural elements of the RFP process to reduce timelines and complexity.* Long RFP timeframes typically do not match well with study and construction schedules for renewable resources. The length of the process also may result in missed opportunities.

- *Harmonize RPS requirements across states and modify RPS requirements that give preference to in-state resources to enable more interstate purchasing.* In-state preferences and varying definitions of renewable energy credits across states may prevent acquisition of higher quality resources in another state and increase RPS compliance costs. Utilities called for harmonization of credits in the West or a federal renewable energy standard that would provide definitions and a framework but allow states to determine their own levels of renewable resources for compliance.

- *Remove all subsidies.* Federal and state subsidies for renewable energy projects create a barrier to robust energy markets in the long run.

- *Pass federal carbon legislation.* The lack of clear federal policies makes resource planning and procurement difficult, according to some utilities. Markets are unsure of what is coming, making project financing difficult.

- *Implement a pre-construction approval process that gives utilities assurance of cost recovery.* Many utilities spoke of the risk they incur in making early investments in renewable energy and transmission projects (prior to when the project is needed to meet increasing RPS targets) which the PUC may disallow in a cost recovery proceeding once the project is in service. Some form of pre-construction approval is important given the long timeframes involved in resource planning, resource procurement and transmission development, as well as changing state policies, according to some utilities.

- *Clarify BPA policies regarding wind generation during high wind/high water/low load conditions.* Seasonally high levels of wind and hydro generation in the Northwest have led BPA to curtail wind generators. Northwest utilities said the region needs clarity on how BPA will address this issue in the future.

- *Provide federal assistance for siting and financing large transmission projects.* Siting impediments and lack of private investors make it difficult for transmission projects to go forward. The federal government can help overcome these issues and get lines built, utilities say.

2.3. Drivers in Renewable Resource Selection

Utility resource planning and procurement personnel identified the following as key drivers in renewable resource selection:

- Cost/cost-effectiveness of the resource
- Transmission and interconnection issues
- Completion risks[59]
- Cost recovery
- Capacity and energy value
- Environmental impact[60]
- Variability and integration costs
- Legal or regulatory requirements (e.g., state RPS requirements for specific technologies)
- Location of project – in state vs. out of state[61]
- Maturity of technology
- Customer preferences
- Permitting progress
- Portfolio balance and diversity
- Tax and subsidy treatment
- Timing of delivery, including coincidence with peak demand

The overwhelming driver, identified as key by 24 of the 25 utilities interviewed, is the cost or cost-effectiveness of the resource. Most utilities identified transmission and interconnection as key drivers for renewable resource selection. This category included a range of issues such as proximity of the project to available transmission, queue position for interconnection and ease of interconnection. Completion risk associated with a particular project, identified by half the utilities, covers concerns such as the developer's financial soundness, site control, and whether sufficient financing is in place to complete the project.

[59] Including whether the project site is secured and the developer is operationally and financially viable.
[60] Includes a variety of environmental impacts, such as water consumption.
[61] Interests cited include RPS multipliers for in-state projects, local job creation and local carbon reduction.

2.4. Specifying Renewable Resources in Planning and Procurement Processes

Utility Resource Plans

In general, utilities stated that their resource plans, both near and long term, contained little specificity regarding types, project sizes or locations of renewable resources, except for commitments already made over the next two or three years and any particular resource types that may be required under a state RPS.[62]

Four utilities identified preferred renewable resource types in their planning process. These utilities cited reliability, balancing and achieving a balanced portfolio as the impetus. One utility stated that it assumes all renewable resources are wind projects in its planning process, because they have been lowest cost in previous solicitations. Another said resource-specific targets could not be counted on because its RFP process is technology-neutral. A third utility identified specific renewable resource technologies in its long-term plan in order to send a message to developers that the utility would like to diversify its portfolio of projects.

Lawrence Berkeley National Laboratory recently completed a summary of incremental generation and retirements during the period from 2011 to 2022 for 27 LSEs based on review of resource plans and a survey of resource planners.[63] The findings are consistent with the WGA interviews.

Utility Solicitations

Most utilities stated that the type and location of renewable resources ultimately procured are the result of a competitive bidding process. Renewable resource projects chosen through the process generally are those with the lowest cost and have transmission available from the project site. Some utilities include locational requirements or preferences in RFPs.

A majority of the utilities interviewed expressed technology neutrality for renewable resources, with 16 of the 25 utilities stating it was the company's practice to issue technology-neutral RFPs for renewable resources. The most common reason cited was cost outweighing technological preference. Some utilities noted that exceptions might be made on occasion, such as a technology test. In addition, state or utility programs may require acquisition of specific resource types and technologies.

Five utilities stated that they conduct some technology-specific solicitations for one or more of the following reasons:

- The PUC directed the utility to issue a technology-specific RFP.
- The utility wanted to acquire geothermal projects because they are base-load facilities.
- The utility had an abundance of wind and issued a solar RFP to balance its portfolio.

Only four utilities expressly conduct technology-specific RFPs systematically. Some of these utilities noted that the choice was driven by IRP results.

[62] One utility stated that it had previously specified locations for renewable resources in the planning process but found that the practice was not useful.

[63] Peter Larsen, Lawrence Berkeley National Laboratory, Sept. 26, 2011. *See* http://www.wecc.biz/committees/BOD/TEPPC/Shared%20Documents/TEPPC%20Production%20Cost%20Model%20Data/Raw%20TEPPC%20Data/Raw%20TEPPC%20Data%20-%202022%20Dataset/IRP%20Resource%20Information/TEPPC_2011_IncrementalCapacity_Retirements_Sep26.xls.

2.5. Coordination of Resource Planning and Transmission Planning

FERC-Mandated Separation of Merchant and Transmission Functions

FERC Order 717 has alleviated many of the restrictions on communication that created roadblocks to coordinated transmission and resource planning under FERC Order 889, according to the utilities interviewed.[64] Many transmission planners noted that they no longer feel restricted in their ability to coordinate with the resource side of the company, particularly when preparing an IRP.

At the same time, some utilities expressed a general feeling that planning is not as efficient as it could be, and that transmission planners are unable to communicate with resource planners to the extent they would like to. According to one utility interviewed, constraints placed on the transmission side of a utility can cause uncertainty or nervousness over potentially costly missteps, leading transmission managers to react to requests from merchant developers and others, rather than taking a proactive, visionary role.

Coordinated planning seems most difficult in the context of near-term planning. For example, it might be difficult for resource planners to access clear information regarding imminent transmission plans. Reacting to an unexpected project proposal for an area in which development was unanticipated also can be difficult.

In reaction to some of these barriers to coordination, one utility suggested further loosening the rules governing standards of conduct for transmission functions of electric utilities. The utility's reasoning is that using OASIS and e-tagging transactions creates an audit trail that would continue to protect against self-dealing, even absent current restrictions on communications. Another step to improve communication between the merchant and transmission functions would be to further clarify the boundaries within which communication can and cannot occur, according to the utility.

Subregional transmission planning can improve communication between transmission and resource planners. For example, BPA collects information about utility loads and where utilities are planning to access power supplies to serve these loads. In fact, one utility noted that its resource planners are more likely to talk to BPA about transmission access, where they are just another potential customer, rather than with the transmission side of their own utility.

Some municipal utilities noted that they are not subject to the functional separation between transmission and merchant functions. However, municipal utilities may have functional separation in certain circumstances, such as where they have voluntarily instituted a pro forma or safe harbor tariff.

Coordinating Transmission Planning With Resource Planning

Today, most IRP processes involve coordination between resource and transmission planners. Utility transmission planners may provide information on request by the utility's resource planning group on occasion, or regular communication between transmission and resource planners may be a key part of the IRP process. For example, transmission planners may be asked to analyze transmission alternatives to proposed generation portfolios. Other information provided by transmission planners to inform the IRP process includes proposed transmission projects, an estimate of when transmission capacity will become available, and details on permitting timelines.

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[64] FERC Order 717, 125 FERC ¶ 61,064, Oct. 16, 2008, http://www.ferc.gov/whats-new/comm-meet/2008/101608/M-1.pdf. FERC Order 889, 75 FERC ¶ 61,078, April 24, 1996, http://www.ferc.gov/legal/maj-ord-reg/land-docs/rm95-9-00k.txt.

Sharing of information between transmission and resource planners is not limited to the IRP process. It also can arise through the competitive bidding process, to the extent resource planning staff are responsible for analyzing bids.

How IRPs Inform Transmission Planning

Cross-pollination between transmission and resource planning is a dynamic and iterative process, where information from the transmission side influences resource decisions and *vice versa*. Transmission projects can first be proposed in IRPs or in response to interconnection service requests. Opportunities for collaboration also may arise through subregional transmission planning.

The IRP process often informs transmission planning, both through the dialogue around resource plans and through the content of the IRP itself. The IRP can serve to validate the transmission plan, providing periodic feedback on whether changes are needed to accommodate projected resource development and acquisition.

Timing limits an IRP's influence on transmission decisions. Transmission can take a decade or more to permit and build, while an IRP action plan may focus only on the first few years of the planning horizon. One utility explained that IRPs generally are too indeterminate to inform transmission planning; until an RFP is issued, there is no concrete information on where new resources will be located.

Utilities that serve as balancing authorities have added scope to their transmission planning processes. They collect information about projected load growth and generation mix from load-serving entities (LSEs) within their balancing area and use the data in transmission planning. One such utility said its interaction with its own procurement staff mirrors its interaction with procurement personnel at other LSEs within the balancing area.

Resource Planning Horizons to Timely Inform Transmission Needs

Most utilities interviewed have transmission and resource plans that extend 10 years or more into the future. However, the long lead times needed to build transmission, combined with the relatively short timeframes for developing renewable resources, limit the ability of resource planning to affect transmission decisions.

Several utilities noted that it takes longer than 10 years to develop a large interstate line. Right-sizing transmission lines could help address the risk that despite long-term resource planning, transmission may not be available to deliver resources planned to come on line in 10 years.[65]

To address this chicken and egg problem, one utility made a decision several years ago that it would build transmission in advance of resource approval, in order to ensure access to resources in its long-term plan. As another utility put it, "We don't get a lot of developers coming in with a wind plant 10 years from now. They want to come on-line in two or three years, maybe four years."

In addition to transmission planning at the utility level, subregional and regional planning processes can play an important role in supporting development of renewable resources and associated transmission. One utility noted that subregional planning groups, the California Independent System Operator (CAISO) and Northwest Power and Conservation Council produce long-term forecasts that can timely inform

[65] *See* right-sizing discussion in Chapter 3.

transmission planning by projecting future energy needs and increases in renewable resources. Another utility pointed toward WECC's 20-year transmission expansion plan, under development.

Several factors limit the influence that resource plans have on transmission decisions 10 years in the future. For example, development of smaller-scale resources close to loads will reduce the need for transmission additions, but the scale and pace of such development is difficult to predict. The extent to which out-of-state resources and unbundled renewable energy credits are used for compliance with RPS requirements also will have a significant effect on transmission decisions. Perhaps the most difficult transmission issue for renewable resources is securing financial commitments from end-users far enough in advance to support a transmission line.

2.6. Utility Comparison of Local vs. Remote Renewable Resources

Some utilities have explicitly compared renewable resources within or close to their service area versus high capacity-factor resources that require long-distance transmission in IRP and competitive bidding processes. The primary metric utilities use for such comparisons is delivered cost, including busbar, transmission[66] and integration costs.

Utilities cited pancaking of transmission rates as a key reason that remote renewable resources may not be cost-effective. One of these utilities performed some rough calculations on whether high capacity-factor wind resources in Wyoming could compete with wind resources closer to the utility's service area and determined that rate pancaking would drive the cost of the higher-quality resources far too high.

Another utility pointed out that a project may be quite distant from a utility's service area but require only one wheel,[67] whereas a close-in resource may require two or more wheels and have a higher transmission cost. At the same time, because transmission typically is not a major part of the total resource cost, the utility said it can "afford" to look at resources in other jurisdictions. However, the relatively low capacity factors of wind and solar resources, compared to base-load resources, have a significant effect on transmission cost.

Although utilities generally will develop or contract for distant resources if they prove more cost-effective, most stated a preference for local resources. In part, utilities are concerned about the risks inherent in projects involving long-distance transmission, including siting and timeliness of project completion. Related, utilities are concerned about regulatory approval and treatment of potential stranded costs. Several utilities simply do not consider acquiring resources where existing transmission is not available.

One utility prefers local resources to ensure service to load pockets.[68] Some utilities do not consider remote renewable resources because they have abundant high-quality renewable resources locally to meet renewable resource requirements. Further, one utility stated that importing remote renewable resources is not an issue because one of its goals is *exporting* abundant local renewable resources to other utilities.

[66] One utility assumes $10 to $20 per MWh for long-run transmission cost as a gauge for considering distant resources.
[67] "Wheeling" is transmission of electricity by an entity that does not own or directly use the power it is transmitting.
[68] A geographic area where transmission congestion prevents exclusive reliance on electricity generation from suppliers outside the area.

A Northwest utility said existing transmission rates are "dirt cheap" compared to building a new line, so it can afford a lower-quality, local wind resource rather than a higher quality resource that is further away. The utility will use only existing transmission capacity until it is no longer available, and it is stockpiling leases for local wind sites to mitigate the risk that other utilities will lock up the best sites. However, some Northwest utilities said new lines out of Montana could make Montana wind cost-effective for them.

One utility noted that even where valuable resources and transmission capacity are available near loads, environmental restrictions may preclude development of projects in those areas, pushing development further out.

For utilities within the CAISO footprint, resource adequacy requirements are another factor they consider. Renewable resources other than base-load facilities are discounted toward meeting these requirements, and transmission constraints may preclude them entirely.

Diversifying resource types and acquiring renewable resources with less variability also are considerations among the utilities interviewed. In addition, one utility mentioned its interest in procuring hydroelectric resources and associated transmission that could help integrate variable energy resources. Utilities also are increasingly considering the shape of the wind output when reviewing projects.

One utility referred to the "economic reach" of renewable resources: "Just like if you ran a restaurant, there's an economic market from which you draw." The utility's view is that wind will serve areas where there's abundant wind, and solar will serve areas where there's abundant solar. The utility does not view "mega-transmission" projects as highly likely to be built.

Conversely, another utility noted that it gets nearly all of its resources 500 miles to 1,000 miles away from load centers. While other utilities may not need to go that far to meet near-term needs, they still may need long-distance transmission to acquire large-scale renewable resources in the future.

Utilities generally were uncertain about the point in time when they might access remote, high-quality resources, rather than rely on closer sites with lower quality resources. One utility said that it has already reached this crossover point, stating that some projects requiring up to 100 miles of radial transmission are cost-effective today. Another said the crossover point could occur in one year or 10 years in the future, depending on the cost of resources that bid into its solicitations. Some utilities don't see a crossover point occurring in the next 10 years, if ever.

Utilities cited a variety of factors affecting when this crossover point may be reached, including the type of resource they acquire, the pace of distributed generation, availability of local resources and transmission, renewable resource requirements and potential carbon legislation. Some utilities said they had not yet reviewed a project in which a higher resource capacity factor justified the increased transmission cost of resources distant from their service areas.

Also raised in relation to this question are reasons for building transmission beyond accessing resources – for example, to reach markets and maintain reliability. Renewable resource projects may be able to piggyback on lines planned for these other purposes.

2.7. Owned vs. Purchased Resources

Utilities typically have a combination of owned and contracted renewable resources. However, most jurisdictions indicated that the utilities they regulate generally prefer to own resources, rather than enter into power purchase agreements, for several reasons:

- Owned resources are included in the utility's rate base, providing the opportunity to earn a return on the investment.
- The utility can avoid a downgrading of its credit rating for taking on debt (power contract) without the benefit of an asset (owned resource) as collateral.
- The utility has full control over operation of the facility.

Ownership does not necessarily mean the utility develops the resource; under "turnkey" (or "build-own-transfer") agreements, an independent developer turns over the project for utility ownership upon demonstration of commercial operation. For that reason, and because utility "benchmark" (self-build) options may be included in competitive bidding processes, competitive bidding may result in utility-owned resources. Utilities also undertake expansions at the facilities they own.

Some jurisdictions have resource procurement policies that encourage transferring cost, financing and performance risk to independent power producers or, at a minimum, require consideration of these benefits.[69] In fact, some states have an overarching preference for power purchase agreements, while recognizing that utilities have capital to facilitate projects that otherwise may not get off the ground. In addition, some states have explicitly authorized utility rate-basing of solar energy systems as part of a larger renewable energy program or legislative package.

Competitive bidding rules may require explicit consideration during the competitive procurement process between self-build options, turnkey offers and power purchase agreements.[70] A couple of jurisdictions noted that where the regulator or utility prefers power purchase agreements, joint ventures among utilities may change that viewpoint.

One jurisdiction pointed out timing differences for retail rate impacts between power purchase agreements and utility-owned projects whose cost recovery is front-loaded. Another jurisdiction noted that lack of transmission limits independently owned projects. Once transmission is available to an area rich in renewable resources, there will be many parties interested in developing generating facilities.

A utility's preference for owning generating facilities versus relying on power purchase agreements – or state/provincial regulations that lean in a particular direction – has little effect on acquisition of resources from WREZ hubs, according to most state PUCs and provincial energy ministries. However, a few jurisdictions believe such preferences may affect where resources are developed.

One state regulator believes that the bias of investor-owned utilities toward owned resources means they likely forego some power purchase agreements that would be preferable for retail customers. Another believes that a preference for owned resources makes development of WREZ hubs less likely.

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[69] In Alberta, all energy sales are transacted through the Alberta Electric System Operator (AESO) pool. However, some competitive retailers and large industrial customers build their own generation as a hedge.

[70] For example, *see* Guideline 10d in Oregon PUC Order No. 06-446: http://apps.puc.state.or.us/orders/2006ords/06-446.pdf.

Utilities tend to develop projects within or close to their service area, while merchant developers may be tied to more distant sites and have a greater appetite for risk.

On the other hand, one regulator pointed out that more distant resources require longer-distance transmission, which may mean higher costs and potentially lower profits for the project. That might make independent power producers less likely to tap distant WREZ hubs.[71] As a counterbalance, this regulator pointed out that utilities have eminent domain authority only for in-state projects, so they may be reticent to acquire out-of-state projects where new transmission is needed. Independent developers generally do not have any such authority.[72]

2.8. Distributed Generation Trends

In response to a question regarding types of renewable energy generation that may dominate in the future, solar was by far the resource most utilities cited – both rooftop PV and utility-scale systems. As expected, Southwest and California utilities placed a much higher emphasis on solar than other utilities. Many utilities expect a continuing reliance on wind resources. Utilities anticipate that other resources will play a smaller role – combined heat and power, biomass, biogas and geothermal. Appendix D lists distributed generation set-asides in state renewable energy standards as well as the amount of distributed resources forecasted by the utilities interviewed.

Two interesting comments arose in response to the question on distributed generation. One utility said it combines its acquisition of distributed generation resources from individual customers with demand response efforts, helping customers curtail their loads while acquiring the customer's excess generation supply. The utility expects this kind of customer relationship to be the norm in the future. Another utility pointed toward distributed generation reducing transmission needs, making it a particularly attractive option.

A nearly unanimous expectation on the part of utilities is that the cost of generation from renewable resources will continue to trend downwards for the foreseeable future, both for distributed and utility-scale generation. While most answers focused on solar PV, there was general agreement that all types of distributed generation would experience cost reductions. There also was near unanimity of opinion that utility-scale generation will continue to cost less than customer-level distributed generation. Utilities offered various views to support this position, including better economies of scale and tracking for concentrated solar power that enables higher production factors.

2.9. Evaluating the Impacts of Future Environmental Regulations

Of the 25 utilities interviewed, six model the potential impact of future carbon regulation and 12 model the potential impact of future regulations for both carbon and criteria air pollutants in IRP, long-term procurement processes or both. The remainder did not indicate any type of modeling activity in this area.

[71] In contrast to investor-owned utilities with cost recovery and authorized return on equity set in rate cases.
[72] Montana's eminent domain law is an exception. *See* Section 3.10.

Criteria air pollutants include particulate matter, ground-level ozone, carbon monoxide, sulfur oxides, nitrogen oxides and lead.[73] Coal-fired power plants are principal emitters of these pollutants, and increased regulation may have a significant impact on their operation.

Over the next few years, in response to legal obligations, EPA will be issuing new public health and environmental rules that will affect coal plant operations, including a new Clean Air Transport rule, mercury and air toxics rule, CO_2 regulations, an effluent rule, 316(B) rule and rules for coal combustion residuals.[74] Several utilities identified Best Available Control Technology (BACT) [75] as a vehicle for addressing criteria air pollutants.

Of the utilities interviewed:

- Only one utility said the new EPA rules will prevent new coal plants from being built. The utility models the potential impact of both carbon and criteria air pollutants.
- Among other utilities that model both carbon and criteria air pollutants, four said the modeling did not point toward coal plant closures; two are undecided about the impact, and the remainder did not address this issue in the interviews.
- Of the six utilities that modeled only potential carbon regulation, one is undecided about the impact on coal plant operations and the other five did not address the issue.

2.10. Effect of More Stringent Environmental and Renewable Energy Standards

Table 9 lists carbon and high RPS scenarios evaluated in resource planning and the resulting increase in the level of renewable resources in those scenarios. The dominant view of utilities is that while carbon regulation and increasingly stringent RPS requirements may increase the *levels* of renewable resources they acquire, the *location* of these resources would remain largely unchanged. One utility noted that high carbon costs and stringent RPS requirements would cause the utility to seek out more renewable resources that are coincident with peak load. Several utilities have not incorporated new environmental regulations in their IRP modeling; others are in the process of evaluating such questions.

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[73] *See* http://epa.gov/airquality/urbanair/.

[74] *See* David Farnsworth, Regulatory Assistance Project*, Preparing for EPA Regulations: Working to Ensure Reliability and Affordable Environmental Compliance*, July 2011, http://raponline.org/document/download/id/919.

[75] "BACT [Best Available Control Technology] is an emissions limitation which is based on the maximum degree of control that can be achieve[d]. It is a case-by-case decision that considers energy, environmental, and economic impact. BACT can be add-on control equipment or modification of the production processes or methods. This includes fuel cleaning or treatment and innovative fuel combustion techniques. BACT may be a design, equipment, work practice, or operational standard if imposition of an emissions standard is infeasible." *See* http://www.epa.gov/NSR/psd.html. BACT applies only to criteria air pollutants, not to carbon.

Table 9. Utility Evaluation of Carbon Cost and High RPS Scenarios in Resource Planning

Utility	Level of Testing for Scenarios Carbon Cost (per ton of CO_2)	High RPS	Increase in Renewable Resources From Base Level
APS	$0, $20, $50	15% and 30% by 2025	Base level of 15% vs. 30% high case
Avista	Considers scenarios at specific levels	Considers scenarios at specific levels	NA
BC Hydro	Considers scenarios at cost levels from zero to ~$70 ($CAN/metric tonne) in 2020	93%[76]	NA
Colorado Springs	Low, Medium, High scenarios ranging from $9 to $30	10%, 20%, 30%	Base level of 20% vs. 30% high case
El Paso Electric	$8, $20, $40	Do not test	Very little impact
EWEB	Considers high test case[77]	Do not test	Currently evaluating
Idaho Power	$0, $15, $20, $25	Do not test	Very little impact[78]
IID	High carbon case	High renewable resources case	Significant impact
LADWP	Considers scenarios based on likely legislative outcomes	Considers scenarios based on likely legislative outcomes	20% to 35%
NV Energy	Do not test	25% by 2025	NA
NWE	$10.57 by 2017 to $105 by 2029[79]	NA	Very little change
PacifiCorp	$19, $25[80]	NA	Unclear[81]
PG&E	Consider scenarios ranging from $10 to $50	NA	Twice as high
PGE	$0 (no compliance requirement), $12, $20, $30 (base case), $45, $65	Uses a series of resource portfolios	NA
PSCo	$20, $40	NA	Depends on natural gas prices[82]
PSNM	$8, $20, $40 in 2010 escalating by 2.5% annually	Four scenarios based on New Mexico's RPS	NA
PSE	$0.32, $19, $38	Does not test	No specific magnitude of increase, but anticipates needing to acquire more wind
SMUD	Considers a variety of scenarios	Considers scenarios ≥33%	NA
SRP	Considers a variety of scenarios	NA	NA
SDG&E	$18.26, $24.35, and $30.44 (in 2015); $32.44, $43.52, and $54.06 (in 2020)	20%, 33%	To achieve 33% and accounting for load growth requires doubling renewables from 2010 to 2020
Seattle City Light	Considers scenarios ranging from $10 to	Considers scenarios with	Did not model

[76] BC law requires 93 percent clean energy resources.
[77] High carbon test case derived from the 90th percentile of Northwest Power and Conservation Council's forecast range of carbon costs, which reaches $100 per ton of CO_2 by 2021.
[78] Analyses have found no change until adders are in the range of $75 to $80.
[79] Test case based on Northwest Power and Conservation Council's average carbon tax.
[80] *See* www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2011IRP/PAC_2011IRP_PortfoliooDevelopmentCases_12-7-10.pdf.
[81] The utility mentioned an estimated range of 300 MW to 2,000 MW of incremental renewable resources by 2030.
[82] With carbon costs at $20/ton and natural gas prices at least $6 to $7, the utility sees a significant increase in renewable resources.

Utility	Level of Testing for Scenarios Carbon Cost (per ton of CO_2)	High RPS	Increase in Renewable Resources From Base Level
	$100	renewable energy credit costs from $7 to $65 per MWh	
SCE	$10-$11 for 2012 and $40-$50 by 2020[83]	NA	NA
Tacoma Power	Considers scenarios based on estimates in federal bills[84]	Does not test	No increase
Tri-State	Considers 24 scenarios ranging from $0 to $61 in 2020	Considers 24 scenarios ranging from 10% to 20% in 2020	Anticipates variability will in effect create a cap for renewable resources
TEP	$25/metric ton in 2015 escalating to $100/metric ton[85]	30% of retail sales by 2025[86]	50%

2.11. Building Flexibility Into Resource Portfolios for Variable Energy Resources

Utilities referred to diverse methods for integrating solar and wind resources into their systems: natural gas and hydroelectric generation, conventional and smart grid-enabled demand response, geographically diverse renewable resources with varying hourly profiles, wind and solar forecasting, and energy storage – pumped hydro, batteries and flywheels.

Several utilities noted that they were conducting integration studies, some within the framework of their resource planning process. Some of these utilities said the impetus for these studies is the lack of flexibility of their coal plants and an anticipated shift to more flexible natural gas plants.

Utilities almost universally stated that they use natural gas plants, with their quick ramping capability, to balance wind and solar resources and plan to continue to do so. However, one utility was not convinced that natural gas peakers are economically superior to demand response, and some utilities were concerned that their current natural gas fleet may be insufficient for balancing sizable levels of variable energy resources.

Demand response was the second most preferred means of balancing solar and wind resources. While one utility suggested that this strategy is largely dependent on the amount of industrial customer load that could be tapped for demand response, other utilities noted the success of demand response programs for irrigation, residential and commercial customers. One utility is planning to aggregate small customers to achieve sizable amounts of demand reduction for balancing. However, utilities noted that aggressive demand response alone would likely be insufficient to balance large amounts of wind and solar. One utility noted the potential to alienate customers by having too many demand response events, particularly if the events do not correspond to the hottest days of the summer when peak utility needs are obvious. Another utility noted the difficulty in relying on demand response for winter-peaking systems.

Acquiring geographically diverse resources was noted for its usefulness in integration. Several utilities pointed out the value of hydroelectric resources for integration, although environmental and recreational concerns limit their usefulness. One utility with a large coal fleet cited the ability to "move

[83] SCE also analyzes a case with carbon twice as expensive as the high case, but considers that scenario unrealistic.
[84] Tacoma's resource mix is 85 percent hydro and 10 percent nuclear, so high carbon scenarios have limited importance.
[85] Base case assumes $5/metric ton in 2018 escalating to $35/metric ton by 2030.
[86] Base RPS case assumes 15 percent of retail sales by 2025.

around" its many individual coal-fired units. Utilities expressed concern about the cost-effectiveness of energy storage strategies.[87]

Some utilities purchase integration services from third parties, and one utility noted that it plans to issue RFPs to solicit a variety of flexible resources. A number of utilities have employed or are considering operational changes, including sharing area control error and intra-hour scheduling, in tandem with subregional planning groups. One utility pointed out that by improving interconnection with other LSEs and market trading hubs, transmission upgrades and new lines help integrate variable energy resources.

A small number of utilities, mostly those that rely heavily on hydroelectricity and do not have a significant amount of solar or wind on their systems, stated that they are not concerned about intermittency issues.

2.12. Cost Recovery for Renewable Resources and Associated Transmission

Utilities consider a wide range of factors in evaluating the likelihood of full cost recovery and profitability for renewable resources and associated transmission. Beyond establishing a clear need for a generation or transmission facility, utilities also must demonstrate that benefits of the project exceed costs. The perspective of investor-owned utilities generally differed from that of consumer-owned utilities on cost recovery issues.

Investor-Owned Utilities – Renewable Resource Development
It is no surprise that two of the most commonly cited factors utilities consider in investment decisions are prudency and used and useful requirements. These are the traditional standards of review for determining cost recovery by a regulated utility for its investments and expenses. Yet the fact that many states have renewable energy requirements, and renewable resources may cost more than traditional sources of generation, changes the way resources are evaluated, particularly with regard to need and cost. Many utilities noted that compliance with renewable energy standards drives investment decisions. One utility underscored its state's mandate that utilities meet these targets with the most cost-effective resources. Some utilities cited penalties for falling short of RPS targets as another driver.

Used and useful requirements were cited most commonly in relation to right-sizing transmission projects. However, one utility noted that the state PUC indicated it would consider acquisition of renewable energy projects prior to need for meeting RPS targets.

A number of utilities identified managing a combination of cost and risk as central to determining the likelihood of a project's success and cost recovery. Several utilities emphasized the importance of timing. For instance, the project must have a high likelihood that it will meet its projected on-line date. Delays can be costly and increase permitting risk. Another consideration is whether there are mechanisms in place that minimize time between the date an asset goes into service and when the utility begins to recover its cost.

In addition to state RPS requirements, federal PURPA law continues to promote renewable resource development. One utility explained that once the PUC approves the utility's contract to acquire power from a PURPA Qualifying Facility, the costs automatically flow into the utility's jurisdictional rates. Thus,

[87] One utility, however, has a 1 MW flywheel test facility.

cost recovery is secured for the utility. However, as with all power purchase agreements, all profits flow to the developer.[88]

Pre-approval, or some sort of acknowledgment prior to constructing or contracting for renewable energy facilities, is one of the primary avenues cited by utilities for evaluating the likelihood of full cost recovery and profitability. For example, in an IRP proceeding the PUC may provide an initial nod for a project that may carry some weight in a cost recovery proceeding. Similarly, PUC approval to issue an RFP, as well as acknowledgment of a short list of bids resulting from that process, provides some level of assurance of cost recovery.

Approval of a Certificate of Public Convenience and Necessity (CPCN) is a stronger form of authorization. As one utility put it, a CPCN serves as recognition by the PUC that the pursuit of the resource is reasonable. So long as the project does not overshoot the cost estimate in the CPCN and is developed prudently, prior PUC orders suggest that cost recovery will be allowed. Another utility noted that in its state, a CPCN for a new generating plant or for a new transmission facility provides pre-approval for cost recovery and generally eliminates the need for a rate proceeding. Cost recovery is assured if the project is deemed prudently planned and remains within a certain range of costs.

Finally, state statute may allow the utility to seek approval for a project from the PUC upfront as part of the IRP or RFP process. If approved, in a rate case the project is deemed to be prudent.

Investor-Owned Utilities – Transmission

Factors considered in determining the likelihood for full cost recovery and profitability for transmission projects are somewhat different from those considered for renewable resources. Reasons include relative cost, long construction timelines, and difficulty in sizing lines to accommodate current and anticipated loads, resource needs and transmission service requests.

Utilities identified need as a central consideration in determining the likelihood of cost recovery for transmission lines. Need may be established through an IRP or transmission planning process. While PUC acknowledgment of a transmission line in an IRP process is helpful, it is not something that a utility can take to the bank, according to one interviewee.

Need also must be demonstrated to FERC for costs that the utility expects to include in tariff rates. In CAISO, determination of need in the transmission planning process was recently expanded beyond customer demand and generator interconnection requests to include policy considerations such as meeting state RPS goals and reaching renewable energy zones identified through the California Renewable Energy Transmission Initiative.[89]

An important factor in establishing need is the extent to which a transmission line will be used to serve native load or to export energy under long-term transmission contracts with third parties. It is difficult to line up sufficient subscription for transmission service or equity partners in a common timeframe.

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[88] Depending on the size of the facility and state policy, the project may receive standard PURPA avoided cost rates under a standard, pre-approved pro forma agreement. Whether a utility may request preapproval for individual PURPA contracts, other power purchase agreements or self-build projects varies by state.

[89] *See* California ISO 2010-2011 Transmission Plan, approved by ISO Board of Governors, May 18, 2011, http://www.caiso.com/2b88/2b8872c95ce10.pdf.

Potential cost overruns are another important consideration in assessing the likelihood of cost recovery and profitability for transmission projects. Stranded costs pose an additional concern. Suggestions on how to mitigate this risk include phasing in a project as needed – for example, requesting cost recovery for segments of a transmission line as they come into service, bringing in partners on a project, and developing multi-use projects that do not rely exclusively on renewable resource development.[90]

Subregional transmission planning also may assuage utility concerns over cost recovery for transmission projects. For example, the Northern Tier Transmission Group's (NTTG) cost allocation committee provides a venue in which state regulatory bodies review proposed cost allocation of planned transmission projects. While proposals are not binding on regulators, NTTG provides an opportunity for PUCs to weigh in on projects prior to construction and therefore provide an early indication to utilities on cost recovery.

As a final note, Colorado's treatment of transmission costs under Senate Bill 100[91] requires utilities under PUC jurisdiction to identify where development of "beneficial energy resources" requires new transmission, to plan for that transmission, and to file applications for approval with the PUC every two years, starting in 2009. The statute also requires the PUC to allow the utility to earn profits on transmission Construction Work in Progress[92] and to put transmission expenditures into rates immediately on incurring them.

Consumer-Owned Utilities

Municipal utilities, electric cooperatives and public utility districts are not rate-regulated in most states, and therefore determination of cost recovery differs procedurally from that of rate-regulated utilities. Further, these utilities are not profit-driven.

Cost recovery for non-jurisdictional utilities begins with project approval by the governing body – the city council or board of directors. The decision of whether to approve a particular project is focused on costs and benefits for the utility's customers. Once the board approves a project, cost recovery is determined in rate hearings before the city council or board. One utility noted that it looks for the least cost, highest value project, the outlay required and how the project pays back over time. Another noted that the main issue is the ability of customers to absorb the cost of developing renewable resources.

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[90] In addition, a utility may seek FERC approval to recover 100 percent of the prudently incurred costs of transmission projects that are abandoned for reasons beyond the control of the transmission owner and are never built or put into service. In order to collect on this incentive once granted, the transmission owner must make a Section 205 filing to FERC showing that abandonment was beyond its control and that all costs proposed to be recovered are prudently incurred. *See* http://www.stoppathwv.com/1/post/2011/06/fercs-transmission-incentives-abandonment.html.

[91] *See* http://www.dora.state.co.us/puc/rulemaking/SB07-100/SB07-100_enr.pdf.

[92] "[S]ome states allow rate recovery of construction costs during the construction process. Known as construction work in progress, the technique involves a commission finding that the utility's project selection decision, and the costs incurred to date, are prudent. This regulatory action eliminates the risk of non-recovery, and allows for recovery earlier. The technique both reduces non-recovery risk and aids in cash flow during construction. Providing CWIP may also reduce a utility's finance costs, as construction financing will be provided by ratepayers rather than lenders or shareholders. Until the investment is moved from CWIP to a plant-in-service account, the utility is permitted to apply a rate of return to the investment amount (which covers its financing costs, *i.e.*, a return on investment)." *See* Scott Hempling and Scott H. Strauss, National Regulatory Research Institute, *Pre-Approval Commitments: When And Under What Conditions Should Regulators Commit Ratepayer Dollars to Utility-Proposed Capital Projects?* at 16, November 2008, http://nrri.org/pubs/electricity/nrri_preapproval_commitments_08-12.pdf.

2.13. Recommended Changes in Cost Recovery to Facilitate WREZ Development

Most utilities identified elements of the cost recovery process that they believe could be improved or modified to facilitate WREZ development and associated transmission. Some utilities, particularly those able to secure approval for projects prior to their development, said no changes are needed. One utility stated that the state's RPS, when combined with stakeholder buy-in for proposed resources, ensures that the costs of associated transmission lines will be recovered. Another expressed satisfaction with the traditional prudency benchmarks of need, least-cost procurement and used and useful requirements. Following is a summary of suggestions from utilities that believe changes to the cost recovery process are needed.

Changes to Cost Recovery for Renewable Resources
Most recommendations for cost recovery for resource development and procurement related to changes in state regulatory processes. One utility set forth a range of policies and considerations that would support cost recovery for development of renewable resources:

- Pre-approve development costs including permitting, even if a project is abandoned
- Provide Construction Work in Progress
- Require a bond from any renewable energy developer
- Allow recovery of research and development costs in retail rates to help drive improvements in renewable energy technologies

Another utility recommended avoiding caps on recovery of costs for meeting RPS requirements. Such cost caps limit the ability of the utility to recover development costs unless the utility can secure a waiver. Additional suggestions included pre-approval processes for renewable resources in designated renewable energy zones or transmission corridors and providing recovery for "dry hole" geothermal drilling costs.

Changes to Cost Recovery for Transmission
Several recommendations for improving cost recovery for transmission to WREZ hubs focused on the federal level. One utility opined that FERC's proposed rules for transmission cost allocation do not provide sufficient incentives or any sort of guarantee of cost recovery for abandoned projects. The utility suggested that FERC mitigate utility risk by increasing returns on high-risk projects, as well as providing a filing mechanism that alleviates utility risk. The utility extended this issue to state PUC determinations on abandoned plant costs. Even where a utility may have recovered abandoned plant costs in the past, more certainty may be needed for large interstate transmission projects going forward.

Another utility noted that while socializing transmission costs may facilitate development in WREZ hubs, in its view FERC's proposal benefits developers while burdening local retail customers. That is, retail customers may end up subsidizing transmission to export resources out of state.

An additional suggestion for federal action is to create a federal "escrow account." The federal government would pay the incremental cost of building extra transmission capacity for some projects and carry that cost until additional users connect to the system. At that time, the project sponsors would buy the capacity. This would temporarily shift the risk of overbuilding transmission capacity from ratepayers to taxpayers, who would carry the initial cost recovery risk, but the costs would ultimately shift to ratepayers as capacity connects to the line.

Turning to the regional level, one utility suggested identification of priority WREZ hubs and transmission corridors leading to specific markets and facilitating cost recovery and permitting for development for this purpose. The utility stressed that anything short of such a comprehensive approach was unlikely to facilitate interstate transmission projects.

Another suggestion, directed at lines for export, is conducting open season processes to establish long-term agreements for transmission service between renewable energy generators and transmission developers or to facilitate equity partnerships. These agreements may in turn facilitate long-term contracts between renewable energy developers and LSEs across jurisdictional boundaries.

In order to address regulatory lag – the time between when the line goes into service and when the utility begins to recover its cost – a utility suggested formula rates for cost recovery or other expedited treatment so that once a resource is in place, the utility immediately begins recovering its cost. A final suggestion was to enact legislation in other states similar to Colorado SB 100, discussed above.

Chapter 3. Transmission Planning and Development

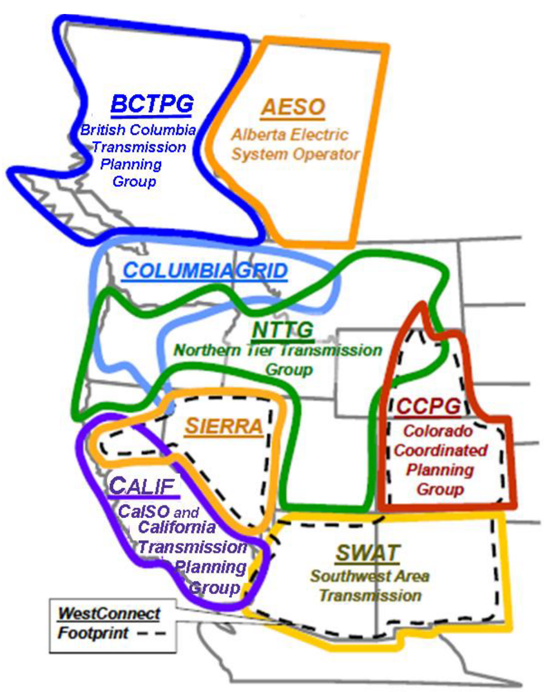
This chapter begins with an overview of transmission planning in the West and utility perspectives on adequacy of transmission to meet renewable resource and environmental requirements over the next decade. Following that are utilities' views on the possible effects of foundational and potential lines on where they acquire renewable resources.

Next is a summary of ways utilities are looking to eke out more capacity from the existing transmission system and potential impact of the freed-up capacity on renewable resource development. The discussion then turns to transmission development issues: joint development and ownership, right-sizing, open season and other development models, barriers to siting interstate lines, and developing lines for exporting renewable resources. The chapter closes with views on institutional structures to successfully develop transmission to WREZ hubs.

Transmission Planning at Three Levels in the Western Interconnection

1. *Utilities and federal power marketing agencies plan transmission to meet load, transmission service requests and public policy directives.*
2. *Subregional planning groups conduct detailed studies of the aggregate plans of affiliated transmission providers and jointly consider planning issues among members and stakeholders. See Figure 9.*
3. *WECC conducts interconnection-wide planning studies with guidance from its Transmission Expansion Planning Policy Committee (TEPPC) using bottoms-up information and stakeholder study requests. TEPPC studies include 10- and 20-year transmission expansion plans that provide an interconnection-wide view of expected energy resources and transmission, as well as transmission requirements and alternatives under a variety of futures.*

Figure 9. Subregional Planning Groups in the West



3.1. Transmission Planning in the West

Following is a summary of transmission planning requirements in Western states and provinces, based on interviews with government officials.

Approval of Transmission Plans by a State or Provincial Body

Some states require regulated utilities to develop transmission plans, though they may not be submitted for approval. Nearly all Western jurisdictions require regulated utilities to develop IRPs that take transmission needs into consideration, though emphasis on transmission varies. CAISO and AESO conduct transmission planning and have authority to order transmission providers to build needed facilities. These processes are detailed below.

Arizona law requires any party that intends to build a transmission line over the coming 10 years to submit transmission plans biannually to the Arizona Corporation Commission (ACC). This is the first step in the Biennial Transmission Assessment (BTA). ACC staff members compile the plans, conduct workshops to obtain further utility and stakeholder input, and analyze the information. Ultimately, the ACC determines whether the plans *in aggregate* are sufficient to meet the existing and expected needs of the state; the ACC does not approve each utility's individual plans. Since 2006, the regulated utilities have been required to draw renewable energy zones as part of the BTA. In 2008, the ACC directed the utilities to develop plans to identify future transmission projects and to propose funding mechanisms to construct the top three transmission projects in their service territories. In addition, the ACC directed the utilities to conduct a joint workshop or series of planning meetings to develop ways in which new transmission projects could be identified, approved for construction, and financed in a manner that supports renewable energy growth.

The Colorado PUC adopted new rules in 2011 establishing a similar process. Utilities are now required in even-numbered years to develop and submit long-range plans specifically for transmission. The PUC consolidates the plans into a single docketed proceeding, reviews the plans and public comments, and determines whether the plans comply with the rules and are adequate to meet the present and future needs of the state. Whenever a utility applies for a CPCN for a transmission project included in its most recently approved transmission plan, any party challenging the need for the requested project has the burden of proving that, due to a change in circumstances, the PUC's decision is no longer applicable or valid.

New Mexico's Renewable Energy Transmission Authority is authorized by statute to "coordinate, investigate, plan, prioritize and negotiate with entities within and outside the state for the establishment of interstate transmission corridors" through participation in appropriate regional transmission forums. Such plans are not subject to PUC approval.

In addition to the above, nearly all Western jurisdictions require regulated utilities to develop IRPs that take into consideration transmission needs.[93] Regulators may approve or acknowledge plans or merely state that a plan meets minimum procedural requirements, depending on the jurisdiction.

[93] Consumer-owned utilities are normally exempt from state IRP requirements but may be required by a federal power marketing agency (Western Area Power Administration or Bonneville Power Administration) to submit resource plans. In some states, IRP requirements do not explicitly require consideration of transmission alternatives, though plans include transmission to deliver selected resources.

In Washington state, for example, utilities must submit IRPs, but the PUC simply determines whether filings are consistent with its rules without passing judgment on the merits of the plans. Similarly, Wyoming PUC staff reviews filed IRPs and reports findings, but the PUC does not make a determination on the substance of the plans.

In British Columbia, BC Hydro must develop an IRP and submit the plan for public review and to a provincial cabinet including the ministers for energy, health and environment. Cabinet approval authorizes the utility to implement the plan. The BC Utilities Commission reviews utility actions for consistency with the plan.

In Nevada, IRP approval by the PUC is tantamount to approval to construct or acquire the transmission resources described in the plan.

In the remaining Western states, the PUC reviews the IRP and makes a determination on whether the plan is acceptable or raises concerns. The PUC also may suggest modifications to the plan or specify exceptions for acknowledgment. If the PUC acknowledges the IRP, it typically conveys a kind of rebuttable presumption that the projects described in the plan, including transmission, seem reasonable. However, favorable ratemaking treatment of transmission lines included in an acknowledged IRP is not guaranteed. Utilities must demonstrate through CPCN and cost recovery proceedings that the investments are prudent at the time the utility made the decision to invest, as opposed to the forecasted conditions in the IRP.

In California and Alberta, the independent transmission system operators (CAISO and AESO, respectively) are responsible for developing transmission plans. CAISO involves the California PUC and other stakeholders in developing its plans, but the plans are not subject to regulatory approval. Similarly, AESO submits its plans to the Alberta Utilities Commission for informational purposes; the Commission does not approve the plans.

Coordination Required With Other Utilities
Transmission planning rules in Arizona and Colorado call for consolidating individual utility transmission plans in a single docketed proceeding. Utilities and other stakeholders, both within and outside the state, have the opportunity to participate in workshops and comment on the plans of other utilities and transmission providers. Cooperation is not required, but it is facilitated by the Commission's involvement. This is intended to lead to a one-system plan that avoids the development of duplicate or unnecessary facilities. Instead, it should encourage development of joint utility projects and ensure each project proposed by a utility does not negatively impact another utility.

In Alberta, provincial regulations require the AESO to consult with provincial utilities and market participants that may be directly affected by a transmission system plan.

CAISO coordinates its transmission plans with all utilities it serves. The California Transmission Planning Group (CTPG) coordinates between CAISO and municipal utilities that manage their own transmission systems. CTPG issued its first statewide plan in 2010.

The remaining Western jurisdictions rely exclusively on subregional planning groups to coordinate planning among transmission providers.

Treatment of Inter-Jurisdictional Lines in Transmission Plans
AESO's transmission plans discuss potential future interties, but such developments are highly dependent on the economics of the lines and the willingness of other parties to build them. CAISO's transmission plans cover interstate lines that would be managed within the CAISO system.

Transmission planning regulations in Arizona and Colorado cover interstate lines that terminate in or cross through the state, but these requirements are no different than for lines contained wholly within the state. In most other Western states, the PUC typically reviews interstate transmission lines included in IRPs using the same criteria as intrastate lines.

Some regulated utilities are owned by a parent company that operates in multiple states and may submit one IRP in all states. For example, PacifiCorp provides retail electric service in six contiguous Western states and owns transmission assets in 10 states. The company submits a system-wide IRP which explicitly considers interstate transmission lines.

3.2. Adequacy of Transmission to Meet Renewable Resource and Environmental Requirements

Utilities were asked whether they have adequate transmission over the next 10 years to meet foreseeable renewable resource requirements and environmental regulations including carbon and other air pollutants.

Transmission to Meet Renewable Resource Requirements
Most utilities say they have adequate transmission in place to meet renewable resource requirements over the next 10 years. For some utilities, this is aided by low load growth and development of renewable resources close to load centers where new transmission is not needed. Other utilities explained that this view takes into account the small additions they plan to make to their transmission system over the next 10 years, but that no new major transmission projects are needed to meet renewable resource requirements. One utility noted that it has adequate transmission to meet its requirements because of its aggressive construction program.

At the same time, some of these utilities point out circumstances under which more transmission might be needed, such as increasing RPS requirements, changes to the utility's resource plan that might require transmission investments for reliability, and accommodating renewable resources for export.

Some utilities stated that they do not have adequate transmission to meet their renewable resource requirements over the next 10 years because of insufficient transmission capacity on the utility's system or broader congestion on the grid. Several utilities are uncertain about whether they have adequate transmission. If renewable resources are developed in remote locations or in congested areas, new lines or transmission upgrades may be needed. In addition, transmission already planned for areas with high renewable resource potential could lead to additional requests for transmission capacity.

Transmission to Meet Environmental Regulations
Few utilities commented on how regulation of carbon and other air pollutants might affect their transmission plans. Some noted that the future of carbon regulation is too speculative at this point to anticipate whether the transmission system will need upgrades over the next decade to address changes in resource mix. Generally, utilities believe it is difficult to predict whether there is adequate transmission 10 years into the future under potential scenarios for carbon regulation.

Plans for Addressing Transmission Gaps
A number of utilities are planning to construct or participate in transmission lines to accommodate new resources over the next decade. Many utilities noted that foundational projects are essential to reliably meeting their renewable energy requirements and that some of the larger projects may take 10 years or more to complete (see next section). Some utilities said modest transmission additions would be needed to accommodate specific areas where renewable resources are being developed.

Several utilities are looking to build transmission to enable export of energy from resource-rich areas to distant load centers. One utility cited its open season process[94] to develop bulk transmission lines for export. Others are in various stages of considering transmission alternatives to take advantage of high renewable energy potential in a particular area.

Many utilities said they rely largely on subregional planning groups and federal power marketing agencies for transmission planning to ensure system reliability and integration of renewable resources in the West.

3.3. Foundational Transmission Lines

A West-wide Subregional Coordination Group, made up of members of each subregional planning group, coordinates interregional planning activities and provides information on expected transmission build-outs and additional proposed lines for WECC's interconnection-wide studies. The Subregional Coordination Group identifies "foundational" transmission lines, more recently called Common Case Transmission Assumptions, which it believes have a high probability of coming into service during the planning horizon of 10 years. WECC includes those lines in its plans as base case assumptions for transmission expansion planning. Figure 10 shows these lines for WECC's 10-Year Regional Transmission Plan for 2020.

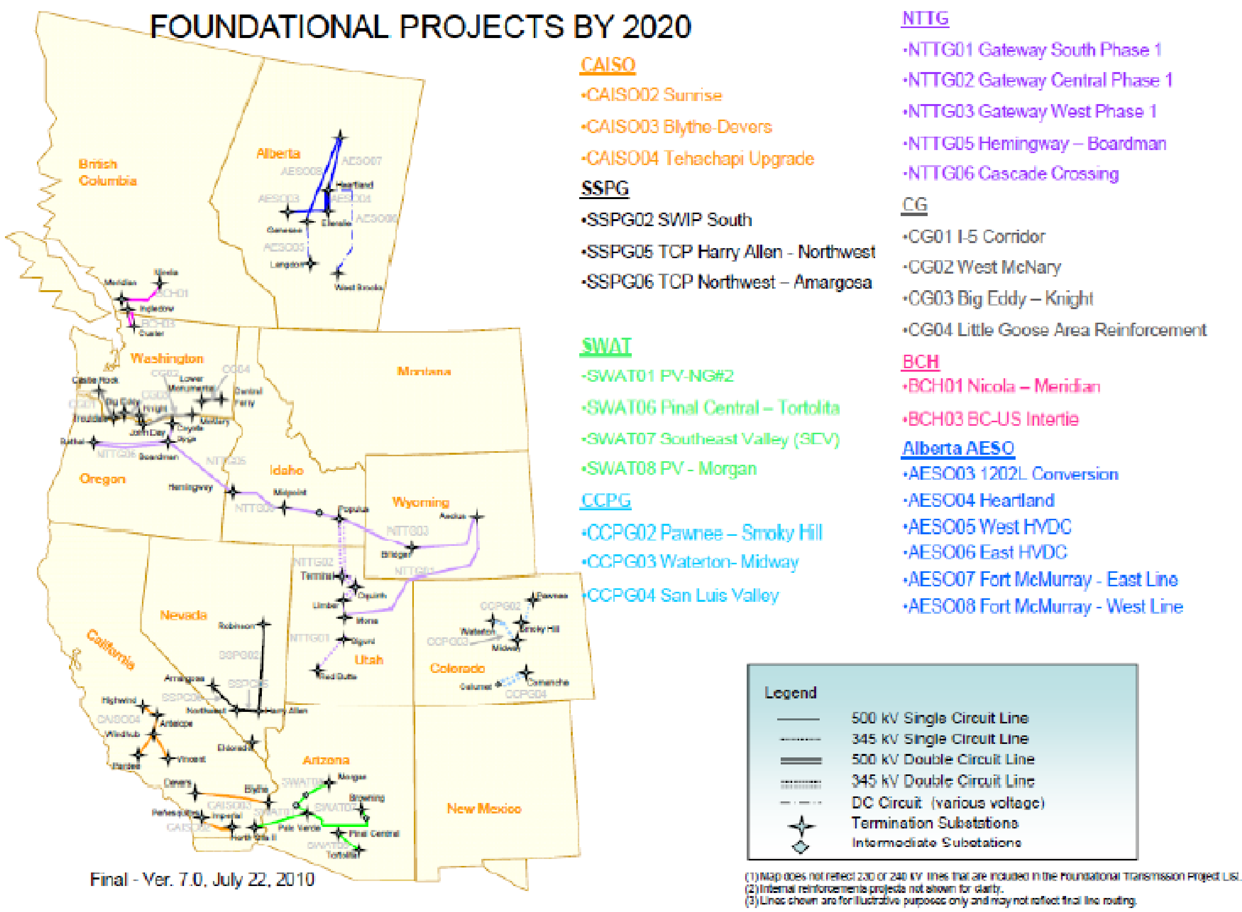
Many of the utilities interviewed for the WREZ initiative said these foundational lines would have an effect on where the utilities acquire renewable resources. However, other utilities said these lines had little influence on their resource acquisition decisions for a variety of reasons:

- Adequate local resources to meet renewable energy requirements
- Sufficient transmission capacity
- Low load growth
- Low likelihood of linking to high-voltage lines to deliver resources to their service area
- A focus on building renewable resources to connect to local distribution lines rather than investing in new transmission
- Plans to develop transmission in different corridors
- Restrictions on imports for meeting state renewable energy requirements

Following are individual utility views, organized by region, on the relationship between foundational lines and where the utilities will acquire renewable resources in the future.

[94] *See* Section 3.8.

Figure 10. Foundational Transmission Lines, WECC 10-Year Regional Transmission Plan for 2020



Pacific Northwest[95]

Eight of the foundational lines cross the Pacific Northwest, including two in Canada:

- NTTG05 Hemingway-Boardman
- NTTG06 Cascade Crossing
- CG01 I-5 Corridor
- CG01 West McNary
- CG03 Big Eddy-Knight
- CG04 Little Goose Area Reinforcement
- BCH01 Nicola-Meridian
- BCH03 BC-US Intertie

Of the seven utilities interviewed in the Pacific Northwest, two expressed a direct connection between foundational lines and their decisions on where to acquire renewable energy. The Cascade Crossing line, proposed by Portland General Electric, passes through a renewable-rich area in eastern Oregon.

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[95] For a map and references to subregional planning groups, *see* http://www.wecc.biz/committees/BOD/TEPPC/SCG/Shared%20Documents/SCG%20Foundational%20Transmission%20Project%20List%20Report.pdf.

Similarly, BC Hydro noted that the Nicola-Meridian line will have significant bearing on where the utility acquires renewable resources. Without the line, it would be difficult to bring renewable energy from northeast British Columbia to load centers in the south.

On the other hand, Puget Sound Energy's Lower Snake River Wind Energy Project in Washington state, with more than 1,000 MW of capacity when fully built out, will tie into existing transmission lines operated by BPA. Together with other wind projects, the utility's RPS requirements are covered through 2019, so new transmission lines are not a near-term concern.

Avista and Tacoma Power say they have sufficient renewable resources close to their service areas to meet state requirements. Seattle City Light noted that while transmission capacity additions generally are beneficial and could be material to resource decisions, new lines that others are expected to build have not yet been part of the utility's resource decision-making process. One of the main issues affecting the utility's ability to acquire renewable resources is transmission across the Cascades and north to south through Puget Sound. Another constraining factor is local congestion on the bulk electric system.

Mountain States
Seven foundational lines cross the service territories of utilities interviewed in the Mountain states, including Colorado, Wyoming, Idaho, Montana and Utah:

- NTTG01-03 Gateway South, Central and West
- NTTG05 Hemingway-Boardman
- CCPG02 Pawnee-Smoky Hill
- CCPG03 Waterton-Midway
- CCPG04 San Luis Valley

Two utilities in this region agreed that foundational lines are affecting, to some degree, their decision-making process on where to acquire renewable resources. PacifiCorp[96] noted that its planned renewable resource acquisitions rely on the completion of several foundational lines they are sponsoring or may cooperate on. The Gateway South and West lines are key to accessing high-class wind resources in Wyoming. Gateway Central, Hemingway-Boardman and Cascade Crossing also are important to PacifiCorp, not only for acquiring renewable resources but for delivering them to PacifiCorp's system.

Tri-State noted its participation in the High Plains Express project. While several other foundational projects skirt the utility's service territory, Tri-State would likely participate in these projects only for reliability purposes – for interconnection access – rather than for acquiring renewable resources.

Two utilities, Idaho Power and Public Service Company of Colorado (PSCo), noted that drivers other than transmission availability primarily stimulate their decisions regarding renewable resource acquisition. Idaho Power cited its IRP process as well as must-take PURPA projects as the main factors. PSCo pointed toward the requirement under Colorado SB 100 to identify renewable resource projects with high generation potential in or bordering the state, develop transmission plans, and file CPCNs with the PUC to build transmission to these regions. PSCo is a sponsor of several foundational lines. However, PSCo has withdrawn as a sponsor of one proposed line from the San Luis Valley.

[96] PacifiCorp serves Mountain and Northwest states.

Due to its small size, Colorado Springs Utilities primarily monitors the construction of foundational lines for reliability impacts, rather than considering them for resource acquisitions. NorthWestern Energy noted that there are no foundational lines in Montana and that the state has more resources than load, making it a net exporter of electricity.

California
The following foundational lines fall within the CAISO's footprint:

- CAISO02 Sunrise
- CAISO03 Blythe-Devers
- CAISO04 Tehachapi Upgrade

Two California utilities said the foundational lines affect, to some extent, procurement decisions for renewable resources. The Tehachapi Upgrade and Blythe-Devers lines will help Pacific Gas & Electric access renewable resources in-state, though additional transmission lines are needed for imports from the Northwest. San Diego Gas & Electric noted that the California PUC issued an order approving the Sunrise transmission project and obligating the utility to purchase renewable resources associated with that line.

Two utilities pointed out factors other than transmission that are determining where they acquire renewable resources. Imperial Irrigation District is in a zone with abundant renewable resources, so the utility is not looking to build transmission to access additional resource areas. Southern California Edison said the state's renewable energy requirements, and its restriction of imports to fulfill those requirements, are shaping both where CAISO is planning new lines and where the utility will acquire resources.

Southwest
The following foundational lines are located in the Southwest, including Nevada, Arizona and New Mexico:

- SWAT01 PV-NG#2
- SWAT06 Pinal Central-Tortolita
- SWAT07 Southeast Valley
- SWAT08 Morgan
- SSPG02 South
- SSPG05 Harry Allen-Northwest
- SSPG06 Northwest-Amargosa

Arizona Public Service (APS) is the sponsor of two foundational projects: SWAT 01 will deliver energy from in-state solar resources and SWAT 08 will bring resources from northern Arizona to APS' load center.[97] Tucson Electric expressed an interest in three foundational lines, including those running from Palo Verde to Pinal and into Tucson, as well as the Tortolita line.

[97] APS noted that SWAT02, currently recognized as a potential line, also is important for development of renewable resources in Arizona.

For NV Energy, the foundational lines will bring renewable resources in the north and east of the state to load centers in the south. In particular, the Northwest-Amargosa line provides access to the abundant solar resource in Amargosa Valley.

Public Service Company of New Mexico noted that planned transmission around its service territory may allow the utility to tap high-quality wind in the New Mexico East and Central WREZ hubs. However, most of these transmission lines are categorized as "potential" projects. Renewable resources under development by El Paso Electric are likely not the types of projects that foundational lines would service. Rather, these resources are more local and likely to link to the existing transmission system.

3.4. Potential Transmission Lines

Potential lines are those projects that a subregional planning group has identified in a 10-year transmission plan but do not meet the foundational project criteria. See Figure 11. WECC uses these potential lines when selecting additional or alternative facilities for transmission planning studies.

Table 10 shows the potential lines that utilities identified in interviews as *both* likely to be built and affect their resource procurement. Some of these projects, when completed, will provide additional access to resources that does not exist today, allowing new resource areas to bid into RFPs. Conversely, some utilities said that even though they believe some of these potential projects will be built, they will not affect the utilities' resource acquisitions because the utilities are focused on projects in, or closer to, their service areas.

Figure 11. Potential Transmission Lines, WECC 10-Year Regional Transmission Plan for 2020

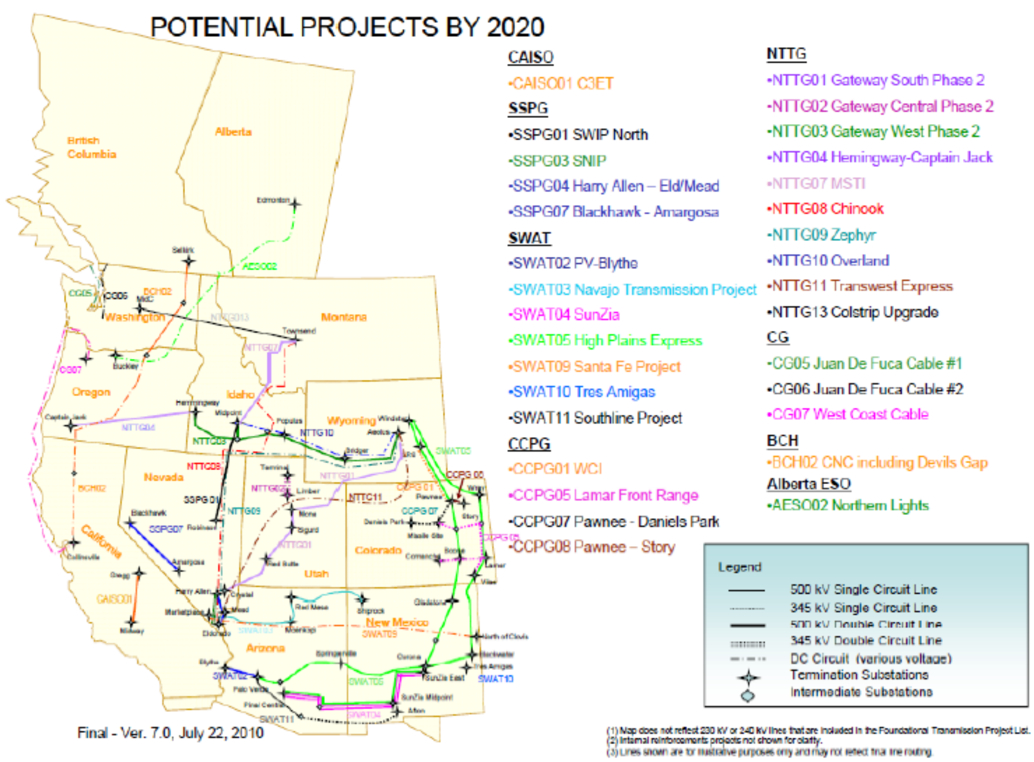

Table 10. Potential Lines Both Likely to Be Built and Affect Utility Resource Procurement, According to Utilities Interviewed

Potential Projects	Project Likely to Be Built and Affect Resource Procurement
CAISO01 C3ET	X
SSPG01 SWIP North	X
SSPG03 SNIP	
SSPG04 Harry Allen – Eld/Mead	X
SSPG07 Blackhawk – Amargosa	
SWAT02 PV-Blythe	X
SWAT03 Navajo T Project	
SWAT04 SunZia	X
SWAT05 High Plains Express	
SWAT09 Santa Fe Project	
SWAT10 Tres Amigas	
SWAT11 Southline Project	
CCPG01 WCI	
CCPG05 Lamar Front Range	X
CCPG07 Pawnee – Daniels Park	X
CCPG08 Pawnee – Story	X
NTTG01 Gateway South Phase 2	
NTTG02 Gateway Central Phase 2	
NTTG03 Gateway West Phase 2	
NTTG04 Hemingway-Captain Jack	X
NTTG07 MSTI	X
NTTG08 Chinook	
NTTG09 Zephyr	
NTTG10 Overland	
NTTG11 Transwest Express	
NTTG13 Colstrip Upgrade	X
CG05 Juan de Fuca Cable #1	
CG06 Juan de Fuca Cable #2	
CG07 West Coast Cable	
BCH02 CNC including Devils Gap	X
AESO02 Northern Lights	

3.5. Increasing Capacity on Existing Transmission Lines

Utilities undertake a range of physical measures to increase transmission capacity on existing lines, including phase shifters, series compensation, shunt capacitors and new wire technologies. A number of operational changes also are underway or under discussion that would free up capacity on existing lines, including increasing demand response, combining balancing authorities, intra-hour scheduling and reducing the duration of transmission contracts.

One option under discussion at the regional level is the development of an Energy Imbalance Market – a subhourly market that would supplement the bilateral market with real-time balancing. The Energy Imbalance Market would allow for more efficient use of the transmission system by enabling real-time access to unused transmission capacity across the region, which could facilitate integration of variable energy resources.[98]

One utility in the BPA footprint expressed concern over another operational change – the use of conditional firm transmission – because it can result in curtailment of firm transmission rights in the hour ahead.[99]

Utility Evaluation of Non-Conventional Mechanisms to Increase Capacity

During the interviews, utilities were asked whether they evaluate potential increases in available capacity on existing transmission lines that could result from: 1) advanced grid technologies; 2) reduced thermal plant operations; and 3) potential market mechanisms to facilitate intra-hour transactions. About half of the 25 utilities interviewed generally do not evaluate these factors. Rather, they undertake case-by-case analysis of the least cost, commercial means to meet native load or transmission service requests using conventional technologies such as capacitors. Reasons include skepticism of untested technologies and methodologies, unwillingness to risk failure of compliance with RPS requirements, or a desire to wait for advanced grid technologies to mature.

Among utilities that do consider new ways that capacity on existing lines may be increased:

- Four utilities consider how smart grid technologies might free up transmission capacity, although one of these utilities voiced concern about relying on immature technology.
- Four utilities consider the potential for reduced thermal plant operations in evaluating available transmission capacity.
- Six utilities consider how intra-hour transactions may free up capacity on the transmission system or plan to consider this at some point in the future.

One utility is considering for the first time in its IRP process how to build out its transmission system, including voltage upgrades, to focus on particular paths in order to acquire preferred resources. Another utility plans to increase the size of its transmission lines to deliver renewable resources and will consider various types of technologies.

Utilities made a few other observations in response this question. First, one utility said FERC rules preventing certain types of communication between merchant and transmission functions of the utility create barriers to identifying opportunities in the resource planning process for evaluating potential increases in transmission capacity on existing lines. Second, a study conducted for CAISO suggests that integrating out-of-state variable energy resources at the source, and using intra-hour scheduling and dynamic scheduling, can provide much of the flexibility the transmission system needs to meet California's renewable energy goals. The study also may indicate where upgrades to the transmission system may reduce the need for new lines.[100]

Finally, one utility noted that its IRP process does not look at increasing transmission utilization because IRP modeling does not fully mimic real-world transmission congestion. This utility believes there is significant "phantom congestion" in the West and therefore more available transmission capacity than

[98] For more on the Energy Imbalance Market, *see* http://www.westgov.org/EIMcr/index.htm.
[99] For a brief description of conditional firm transmission rights, *see* Western Governors' Association and National Wind Coordinating Collaborative, *Conditional Firm Transmission Service Factsheet*, http://www.nationalwind.org/assets/blog/WGA_NWCC_Conditional_Firm_Factsheet.pdf.
[100] *See* http://www.caiso.com/planning/Pages/TransmissionPlanning/Default.aspx.

modeling indicates. The problem, according to the utility, is that historical rules and business practices designed to prohibit gaming the transmission queue restrict legitimate actors seeking access to transmission. The utility is exploring economic redispatch for transmission congestion while also working on increasing physical capacity.

Potential for Increased Capacity on Existing Lines to Drive Renewable Resource Development
Utilities were asked how increasing capacity on existing transmission lines through both conventional and advanced technologies, reduced thermal plant operations, and market mechanisms that facilitate intra-hour transactions might affect *where* they develop renewable resources.

Several utilities agreed that increasing capacity on existing transmission lines has the potential to facilitate development of proximate renewable resources. Some utilities are actively undertaking measures to do so. One utility cited the *Western Wind and Solar Integration Study* as an indication of the potential for incorporating more renewable resources in the West.[101]

One utility explained that the extent to which out-of-state resources will be delivered on freed-up lines depends in large part on eligibility of such resources for meeting RPS requirements. Another utility pointed out that no mechanism exists today to send a locational price signal to construct resources where additional transmission becomes available.

Some utilities said there are insufficient drivers to develop renewable resources to take advantage of newly available transmission capacity, or the amount of freed-up capacity on existing lines may not be extensive enough to affect where renewable resources will be located. For example, one utility noted that upgrades it is undertaking on existing lines will provide significant additional capacity, but as a general matter the utility is not undertaking much renewable resource development. Similarly, a second utility said its fleet of conventional power plants is likely to remain in place for the next decade and therefore the utility has limited plans to develop renewable resources in that timeframe. A third utility said that because it is in a load pocket, a new line would be needed to deliver additional resources.

Another utility noted that partial attempts at market reform will not necessarily send a strong enough signal to develop renewable resources where transmission capacity has become available. Instead, an RTO-type market in the West could send locational signals to drive development where transmission capacity is available.

Freed-up Transmission Capacity Due to Environmental Regulations
Utilities were asked whether reduced coal plant operations or retirements that might result from future environmental regulations for criteria air pollutants and carbon could free up transmission capacity that would be useful for incremental renewable resources. Some utilities stated that there is some potential for renewable resource development in the vicinity of their coal plants. Others are pessimistic about developing cost-effective renewable resources near the plants and believe it makes more sense to build other thermal capacity, such as natural gas plants. Even where renewable energy potential does coincide with the location of a coal-fired power plant, a utility may prefer to develop local renewable resources if that power plant is located out of state.

[101] *See* GE Energy, *Western Wind and Solar Integration Study*, prepared for the National Renewable Energy Laboratory, May 2010, http://www.nrel.gov/wind/systemsintegration/pdfs/2010/wwsis_final_report.pdf.

Several utilities expressed reservations about the overall concept of replacing thermal baseload generation with renewable resources. First, they pointed out that thermal resources have a high capacity factor, while wind and solar resources have a low capacity factor and variable output. Second, they noted that sufficient resource capacity must be available during peak hours. They also emphasized the need for additional balancing resources such as natural gas plants to accommodate high levels of variable energy resources. One utility said a power flow study is needed to determine the effects on reliability of replacing thermal generating capacity with renewable resources, while another utility is in the process of conducting such a study.

Existing system constraints exacerbate some utilities' concerns about maintaining reliability in the face of potential coal plant retirements. For example, a system with transient stability constraints may not be able to replace thermal capacity with renewable resources, according to one Mountain state utility, as variable generation could further destabilize an already unstable system.[102] A Northwest utility said curtailment of thermal capacity would likely cause voltage support problems that could not be solved through replacement with variable energy resources.

Potential Effects of Environmental Regulations on Coal Plants
Several utilities have analyzed the effects of potential environmental regulations on their coal plants including replacement. Some retirements already are planned or under consideration.

One utility said it is constantly studying the impacts of environmental regulations and permitting challenges that might affect the resource mix and associated transmission. A second utility said it is considering ways to replace the capacity of a coal-fired power plant that is slated for retirement, including running the plant with biomass on a seasonal basis. CTPG and WECC studies on these issues can further inform utility planning, according to another utility.

A utility that is not actively studying the impacts of potential environmental regulations on coal plant operation said the lack of carbon legislation to date obviates the need to consider carbon restrictions in planning.

3.6. Joint Development and Ownership of Transmission Lines

Utility Drivers
A number of motivations may drive the decision to jointly develop and own a transmission line with another utility. The most common driver for joint development is a shared need or common goal between two or more utilities. In the words of one utility: "If needs align, the details can likely be worked out." A second utility noted that about half of its 345 kV lines are jointly owned, and that all of these lines were developed based on common needs.

Utilities also cited some of the risks that joint transmission development and ownership can mitigate, including financial risk.

[102] "Transient stability has to do with the system's ability to accommodate sudden changes, such as faults (short circuits), loss of a transmission link, or failure of a large generating unit, and return quickly through this transient condition to a sustainable operating state." Alexandra Von Meier, *Electric Power Systems: A Conceptual Introduction*, 2006, p. 235.

An important consideration is ensuring that all utilities in a transmission project's footprint are involved, according to one utility. This can result in longer timelines, but can help ensure coordination between transmission and generation functions in the planning process.

Many utilities pointed out the importance of ensuring adequate generating resources to support a line. One utility offered two potential solutions: 1) utility ownership of resources and 2) an open season process[103] to secure subscriptions in advance. Lastly, one utility noted that it jointly owns transmission lines that move power out of state.

Utility Experience With Joint Development and Ownership

Nearly all of the utilities interviewed have experience jointly developing and owning transmission projects with other utilities, and several have experience working with merchant developers. For some utilities, partnering is the most common way to develop a transmission line, while for others it is an occasional occurrence or something they are not interested in pursuing at present. Some utilities described situations where they solicited joint ownership or third-party subscriptions for projects they were planning. Others joined a project planned by another utility or jointly identified common interests leading to mutual cooperation on a project.

Typically, securing joint ownership involves identification of a project with potential, inviting other parties to participate, and signing joint participation agreements and memoranda of understanding, followed by subsequent phases for permitting and construction. The timeline for joint planning and development can vary significantly. An agreement to cooperate on a line can materialize within six months of conducting the first planning exercise or take several years to take shape.

Subregional planning groups play an important facilitative role in bringing utilities and other stakeholders together where they can identify common needs and interests, according to the utilities interviewed. One utility explained that it may sponsor a project, based on its own reliability needs, and present the concept in a subregional planning forum. This can lead to a negotiating process where several parties agree to jointly finance the permitting. Those who helped finance the permitting then have the option to own a portion of the project.

Bilateral communication also may lead to joint utility projects. One utility outlined a project and subsequently identified another utility interested in a similar project. Together, they mapped out a transmission line that met the needs of both utilities and proceeded with the project jointly. Another utility noted that it has purchased a share of a project spearheaded by another utility and can foresee launching a project that others would buy into. One utility said its policy for joint participation is based on the idea that the beneficiary pays, and anyone who wants to come to the table with money for a project is welcome to participate.

Only two utilities stated they do not solicit others to participate in transmission projects, nor do they join others' projects. One of these utilities simply stated that it builds projects on its own, though coordination with utilities that want transmission service on the line is necessary.

[103] *See* Section 3.8.

3.7. Right-Sizing Transmission Lines

Right-sizing of transmission lines means increasing project size, voltage or both to account for long-term needs and minimize the need for additional transmission corridors and associated environmental disruption. It ultimately means building some level of transmission in advance of need – for example, building a line to be double-circuit capable or at a higher voltage than initially needed in order to accommodate future growth. Interviews with utilities as well as jurisdictions asked whether statutory or regulatory changes are needed to enable utilities to right-size transmission lines to access high-quality renewable resources.

Utility Views
Most utilities said statutory or regulatory changes would be needed to overcome barriers in the current permitting and cost recovery processes to allow for right-sizing. Some utilities, however, see no need for right-sizing lines or do not see barriers under current regulations.

<u>Barriers to right-sizing</u>. Sizing transmission lines to accommodate forecasted resource development can run up against both regulatory and practical hurdles. A utility must prove the line is a prudent investment and used and useful in order to secure cost recovery. Proving these criteria for a line that is not fully utilized in the early years can be difficult, including accurately projecting demand for the line and financial commitments from other parties for the anticipated additional capacity needed. To the extent transmission expansion is to accommodate projected service to third parties a few years out, there is no revenue to support that investment in the early years.

One utility noted that excess transmission capacity is a central question in determining whether a line is “used and useful” in terms of cost recovery from ratepayers. Another explained that in order to up-size a project there must be a prudency justification for doing so or some way to offload that capacity in the interim. Other utilities noted that lines often are built with some excess capacity due to the “lumpiness” of planning for transmission.

Finding interested parties to financially commit to a line in advance of need is difficult. One utility illustrated the problem anecdotally. The utility secured a CPCN for a 230 kV line. A number of parties pushed for a bigger, 345 kV line. In response to the demand for more capacity, the utility conducted a process to determine interest from anyone willing to pay for the upgrade. There was only one response, which was withdrawn after further analysis. The utility plans and builds for its own needs and does not have support from its board to right-size a line where the benefits are speculative.

One utility observed that there is a perception that transmission lines are being built at too low a voltage, but that historically low-voltage lines have returned benefits to ratepayers. Moreover, advocating for right-sizing can prevent a line from being built simply by escalating the scope of the project. Still, the utility has justified right-sizing a line in order to accommodate some growth potential, to improve conductance over long distances, and because the utility was able to share risk by partnering with a commercial developer on the project.

Utilities also raised the issue of who bears the risk that the line will not be fully utilized, as well as the inverse risk of building a lower-voltage line only to discover that more capacity is needed.

Several utilities said upsizing lines is not problematic for them for the following reasons:

- Consumer-owned utilities can secure permission from their board or city council for right-sizing a line if it makes sense to do so.
- A long-term view in planning enables right-sizing.
- The state legislature and PUC have encouraged building transmission lines to accommodate future growth.
- CAISO's transmission tariff allows right-sizing, and the California PUC has expressed willingness to approve right-sizing to further the state's policy supporting renewable resources.

Statutory and regulatory changes. Utilities offered a number of suggestions for legislative and regulatory changes that could facilitate right-sizing transmission lines to enable development of WREZ hubs. Recommendations primarily focused on securing assurance of cost recovery. There also were suggestions on how changes at the federal level might facilitate right-sizing. Several utilities suggested specific adjustments to siting and approval processes. Following is a summary of these suggestions:

- Explicitly allow construction of transmission projects prior to need
- Allow consideration of economic development, including exporting resources
- Preempt state RPS requirements with federal RPS legislation or standardize renewable resource requirements throughout the West
- Change the definition of "used and useful" to incorporate broader policy considerations such as right-sizing to support renewable resource development
- Enact legislation authorizing pre-approval of upsized projects
- Amend the environmental permitting process to allow for a wider transmission corridor, providing the option to expand lines in the future
- Site double-circuit towers, allowing expansion of single-circuit lines when the need arises
- Provide meaningful federal backstop authority for siting[104]
- Grant governors the power to overrule local zoning, siting and environmental authorities as a last appeal if a local jurisdiction blocks a project
- Conduct an open long-term planning process that involves stakeholders, developers and utility neighbors

PUC/Energy Ministry Views

Cost recovery, construction preapproval and plan acknowledgment. According to several regulators, oversizing transmission lines relative to near-term needs has at least until recently been common practice. As one regulator put it, "We've been growing into transmission for the last 30 years. When you spend so much money, you don't want to have to go back 10 years later to increase the size of the line." Another regulator views upsizing lines as an intergenerational equity issue – building for the benefit of future generations.

Recent legislation in some jurisdictions recognizes the need to build transmission for the long-run and specifically authorizes right-sizing for clean energy resources. Alberta requires the system operator to plan for transmission needs 20 years in the future and transmission facility owners to build critical facilities to support renewable resource development to the extent merchant developers are not addressing these needs.[105] In British Columbia, the Utilities Commission must consider current and

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[104] One utility noted that the Energy Policy Act of 2005 provides federal backstop authority, but that FERC has not had success in upholding this power in federal courts.
[105] *See* the Alberta Transmission Regulation, http://www.assembly.ab.ca/ISYS/LADDAR_files/docs/bills/bill/legislature_27/session_2/20090210_bill-050.pdf and

anticipated future use of a transmission line in determining the optimal size of project. The Clean Energy Act[106] passed in 2010 requires BC Hydro to submit an IRP to the Energy Minister that includes a description of infrastructure and capacity needs for 30 years, including lines to renewable resource areas, under a range of plausible future scenarios and considering exports.

In California, transmission lines can be approved for policy reasons, providing flexibility to fill up a line over time. Investor-owned utilities seek CAISO approval of a line before they come to the PUC to request cost recovery.

Colorado SB 100 requires regulated utilities to "designate energy resource zones"[107] and every two years "develop plans for the construction or expansion of transmission facilities necessary to deliver electric power consistent with the timing of the development of beneficial energy resources located in or near such zones." Further, the PUC must approve a utility's application for a CPCN for these transmission facilities if they are required to provide reliable delivery of energy for Colorado consumers or meet the state's renewable energy standards and if "the present or future public convenience and necessity require such construction or expansion." The legislation also provides timely cost recovery through a separate rate adjustment clause for all prudently incurred costs for planning, developing and constructing lines for which the utility has been granted a CPCN or for which the PUC determined a CPCN was not required. Similarly, recent legislation in Nevada addresses building transmission to renewable energy zones in advance of need.[108]

But while there may be universal recognition that transmission facilities are lumpy investments, today most jurisdictions find it difficult to approve sizing a transmission line beyond: 1) meeting the definable future needs of their retail customers and 2) fulfilling signed agreements for transmission service. One regulator noted pushback from industrial customers, in particular. Another said its commission has taken a firm line on "excess capacity" on transmission lines and a "fairly narrow view of the benefits."

In some jurisdictions, utilities can receive pre-approval for transmission projects where sizing can be addressed. In others, the process for obtaining a CPCN provides a good indication of the jurisdiction's view of this issue. However, in the vast majority of jurisdictions, utilities find out whether they will receive full cost recovery for their investments after the fact.

For example, the Idaho PUC recently disallowed about a quarter of the costs PacifiCorp requested for the Populus to Terminal line, part of its Energy Gateway transmission project, finding "that the Company has not demonstrated that the line is presently 'used and useful' in its entirety…. The record reflects that the Populus to Terminal line was built to meet not only present needs but future needs…. Idaho, we find, will pay its fair share to meet the Company's system load and transmission requirements but we will not allow full rate-basing of investment in Populus to Terminal prematurely and we will not require Idaho customers to assume and pay for unused capacity."[109]

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http://www.energy.alberta.ca/Electricity/1773.asp. *Also see* the Alberta Utilities Commission Act, http://www.canlii.org/en/ab/laws/stat/sa-2007-c-a-37.2/latest/sa-2007-c-a-37.2.html.

[106] *See* http://www.leg.bc.ca/39th2nd/1st_read/gov17-1.htm.

[107] SB 100 states that an "'energy resource zone' means a geographic area in which transmission constraints hinder the delivery of electricity to Colorado consumers, the development of new electric generation facilities to serve Colorado consumers, or both."

[108] *See* Assembly Bill 387 (2009 Session), http://www.leg.state.nv.us/Session/75th2009/Bills/AB/AB387_EN.pdf.

[109] *See* Order No. 32196, Docket No. PAC-E-I0-07, Feb. 28, 2011, at 37-38, http://www.puc.idaho.gov/internet/cases/elec/PAC/PACE1007/ordnotc/20110228FINAL_ORDER_NO_32196.PDF. This portion of the line's capacity will be placed in plant held for future use.

Utility transmission lines upsized for export raise especially difficult questions for regulators if retail customers are asked to pay for some of the costs, rather than cost recovery solely through FERC tariffs. These issues are further complicated to the extent there are reliability benefits for the utility's retail customers. In addition, some of the utility's industrial customers may wish to import power from out of state over such lines, where they are permitted to do so.

Regulators stated that each case is fact-dependent; if the utility can make the case that building extra capacity today is in the long-term best interests of retail customers, regulators would approve it.

Some state commissions address these transmission issues in part through the IRP process. For example, the Oregon PUC recently addressed the issue of right-sizing in IRPs submitted by the state's three regulated utilities. Its decisions show that the PUC may support right-sizing but that the utility must demonstrate that it is economic for retail customers over the long run, considering third-party equity participation and transmission subscriptions.

For Idaho Power, the Oregon PUC determined that the resource portfolio including the Boardman-to-Hemingway (B2H) line "is the best portfolio for customers over a range of capital costs and third-party subscription levels" and that "it [is] reasonable to proceed with the B2H Project based on the information available now and acknowledge it as part of the Company's 2009 IRP."[110] The PUC required Idaho Power to update its assumptions, including construction cost estimates, equity partnership estimates, third-party subscription estimates and wheeling revenues in its next IRP. The PUC noted that at the time the utility requests to include B2H costs in retail rates, it must show that its investment was a prudent decision, addressing any significant changes in these estimates.

The Oregon PUC made a similar finding for Portland General Electric's (PGE's) Cascade Crossing line, envisioned as either a single- or double-circuit 500 kV line, depending on developments regarding equity partnership interest and third-party subscriptions. PGE analyzed the line under various scenarios for third-party equity participation and BPA transmission rates. With similar conditions as it placed on acknowledgment of Idaho Power's B2H portfolio, the PUC determined that, "PGE's benefit-cost analysis is sufficiently robust, and shows sufficient net benefits under certain scenarios, to allow us to acknowledge Cascade Crossing at this time."[111]

In an earlier decision on PacifiCorp's 2008 IRP, the Oregon PUC acknowledged the company's proposed transmission action items: 1) obtaining a CPCN for segments of Gateway Central and Gateway West and 2) construction of the Populus-Terminal and Mona-Oquirrh segments. The PUC's acknowledgment of these segments was based on analysis showing that portfolios with these upgrades outperformed portfolios without them on stochastic cost, risk and supply reliability measures. The PUC concluded these transmission segments would increase reliability and transfer capability. On the issue of right-sizing, the PUC found that these segments would support integration with larger segments.[112]

Statutory and regulatory changes. Jurisdictions generally find that no changes are required in statute or regulation in order for a utility to right-size transmission lines to access high-quality renewable resources in advance of need. One state regulator expressed concern regarding any changes to the traditional

[110] *See* Order No. 10-392, Docket LC 50, Oct. 11, 2010, at 9-10, http://apps.puc.state.or.us/orders/2010ords/10-392.pdf.
[111] *See* Order No. 10-457, Docket LC 48, Nov. 23, 2010, at 20, http://apps.puc.state.or.us/orders/2010ords/10-457.pdf.
[112] *See* Order No. 10-066, Docket LC 47, Feb. 24, 2010, at 19-20, http://apps.puc.state.or.us/orders/2010ords/10-066.pdf.

regulatory paradigm of case-by-case determinations of whether a utility investment is just and reasonable and in the public interest.

However, some regulators acknowledged that utilities were likely to pursue changes in state statutes to address used and useful provisions that may be of concern in sizing lines, as well as to address eminent domain[113] to build wind collector systems to get to transmission lines.

According to one regulator, the fundamental problem for customer-based funding is the long timeframes required for transmission planning, development and construction. Therefore, only federal funding can solve the issue of right-sizing. Further, to the extent society at large benefits, rather than just the state's residents, the federal government should pay for the "social increment" of the line.

3.8. Open Season and Other Development Models

Utility Views

A majority of the utilities interviewed welcomed the open season model for developing transmission lines. Utilities described several types of "open season" processes. In one version, the proponent of the transmission project issues an open invitation for other parties to be joint financiers and owners. In a second version, a utility or other entity puts out a call for requests for new transmission service and aggregates them to plan transmission expansion. BPA's prior open season processes, for example, required respondents to sign a service contract and provide a deposit equal to 12 months of transmission service.

Under a third approach, a merchant transmission developer finances 100 percent of a project and allows parties to bid on access to capacity on the line. According to utilities, this approach has not been particularly successful in the West. Developers are trying to get sufficient subscriptions before spending $10 million to $20 million just for permitting. Meantime, resource developers who might subscribe to the line do not wish to commit to a sizable investment many years before the line goes into service.

Another model that utilities mentioned involves a utility, or a joint entity comprised of two or more utilities, developing a line. Rather than an open season process, the utilities identify and reach out to potential subscribers for the line. For example, the utilities may target a large wind developer to be an anchor shipper.

Although supportive of the open season model, utilities noted a variety of challenges to making the process work, including the significant deposit required for resource developers to secure rights to transmission capacity, uncertain RPS requirements, lack of power purchase agreements to support merchant transmission lines, and differing tax treatment for nonprofit versus for-profit entities.

Some utilities said the open season process works for smaller projects with shorter timeframes, but not for longer duration projects designed to cross several state lines. Utilities may consider a phased approach for large projects, where parties funding an initial stage of a project receive an option they can exercise at some point in the future when permits are secured for the entire project.

[113] *See* section 3.9.

One utility has not had any responses to its open seasons for the past several years. On the other hand, an open season process for a joint transmission project between two other utilities received more than 20,000 MW of third-party requests for 3,000 MW of excess capacity available.

PUC/Energy Ministry Views on the Open Season Model[114]

Nearly all Western states and provinces agreed that utilities should consider the open season model to develop transmission lines for a variety of reasons, including the following:

- BPA and natural gas pipelines have had success with open seasons.
- Multiple commitments of sufficient size can justify the expense of a transmission line, as well as garner support for siting approval across jurisdictions.
- Pooling transmission needs and developing higher voltage facilities in fewer corridors reduces the footprint of transmission projects and, therefore, opposition.
- The process may identify interest in developing resources in a common area that can be delivered to a hub for transmission to load centers.

Importantly, open season processes do not remove generators' uncertainty regarding power purchase agreements with utilities. Utilities will not sign such agreements absent transmission assurance, and generators will not make financial commitments for transmission absent a power purchase agreement. Therefore, the open season approach is unlikely to be sufficient to develop transmission to renewable resource areas.

In addition, timing related to siting permits remains a problem. If generators do not have certainty about the date the transmission line will be in service, it will be difficult for them to participate in an open season process.

One PUC suggested testing coordination of renewable resource solicitations among utilities to see where generator interest is highest, then conditionally permitting lines to these areas in order to facilitate an open season process. In the PUC's view, renewable resource developers are in the best position to determine which renewable resource areas to advance. With so many resource development and transmission options, the PUC is trying to figure out which ones make sense and is seeking the assistance of generators in making that determination.

Another regulator noted that utilities may operate a process akin to open season when they announce a potential transmission line. But while there may be significant initial interest by generators in the line, that interest tends to evaporate when it's time for generation project developers to write a check to the utility for equity partnership or to secure transmission service. Despite supporting the concept, several regulators said the utilities they regulate may not want to use an open season approach, in part due to unsuccessful experiences by merchant transmission developers that have tried it.

An important benefit of open season processes is increasing market participation, a prerequisite for getting the best deal for ratepayers, according to one interviewee. This regulator believes FERC has set the right balance in its approval of open season processes, allowing for anchor tenants for the transmission line with the remaining capacity of the line filled up through the open season process.

[114] See Section 4.9.

Some PUCs noted the importance of financial and contractual assurance in an open season process to ensure that the utility recovers its investment costs.

For transmission lines within Alberta, whether built by merchant developers or by transmission facility owners as directed by the AESO, an open season process is not seen as necessary.

PUC/Energy Ministry Views on Other Potential Models
Some jurisdictions identified the regional transmission organization (RTO) model as an alternative to the open season model. RTOs have varying responsibilities and authorities for identifying transmission needs, requiring lines to be built and determining cost recovery and allocation.

Merchant transmission is considered a viable alternative by a few jurisdictions. Another successful model cited is the approach used to develop a transmission line for wind projects in California's Tehachapi area. In order to meet the needs of a renewable resource region instead of a single generation project, in 2007 FERC approved the CAISO's request to acknowledge "Location Constrained Resource Interconnection Facilities" and rate-base transmission developers' initial costs – in other words, include the costs in the transmission owner's revenue requirement and transmission access charges. As generators interconnect to the line, they pay their proportional share of the line until it is fully subscribed and the transmission owner recoups its initial investment.

Legislation also may help solve the chicken and egg problem associated with transmission for renewable resource development. As discussed earlier in this chapter, some jurisdictions explicitly allow approval of utility lines that stem from a sound transmission plan and that demonstrate the line will lead to the intended renewable energy development.

A couple of jurisdictions pointed toward states and provinces that have approved regional transmission solutions that provide more cost-effective solutions for ratepayers. Some regulators said the federal government should pick up the tab for regionally important transmission lines.

One regulator noted that a multiple owner-plus-subscription model may work well. It would combine equity ownership by two or more utilities along with transmission subscription by generators that provides assurance that utilities will recoup the costs of their portion of the line.

3.9. State Policies and Regulations That May Impede Interstate Transmission Development

Utility Views
Two-thirds of the utilities interviewed said state policies or regulations impede development of interstate transmission. Three key issues emerge in the utilities' responses: local siting processes, inconsistent regulatory standards across borders and cost recovery.

Many utilities identified siting transmission projects as a serious problem. Of particular import, utilities contend it is difficult to prove that a transmission line passing through a locale will produce sufficient (or any) local benefits. This makes the siting process long, complicated, costly and potentially unsuccessful.

Utilities also cited inconsistency of regulatory standards from state to state, as well as between state and federal jurisdictions, as a serious impediment to planning and approval for interstate transmission projects. Furthermore, shifting RPS requirements make it difficult to predict whether transmission from a particular WREZ hub to a load center will be useful, because it is unclear which renewable resources will qualify in the destination state over time.

The added risk, time and cost for interstate projects come to a head in cost recovery processes. Given siting and regulatory uncertainties, it is difficult for utilities to demonstrate that interstate transmission projects are prudently undertaken. In addition, lack of harmony in cost recovery processes across jurisdictions poses cost recovery risks that utilities are reluctant to shoulder.

PUC/Energy Ministry Views
State and provincial officials noted several types of policies and regulations that impede the development of transmission projects that cross jurisdictional boundaries. These include demonstration for a given state that a line is needed and will serve the public interest, lack of eminent domain authority, multiple uncoordinated approvals required by various levels of government, and cost recovery processes.

Regarding need and public interest, some state statutes require regulators to view these issues solely from the perspective of ratepayers' needs and the interests of the public *within the state*. That can pose a serious impediment to a proposed interstate transmission line if it crosses over a state without local interconnections to serve in-state load. For a transmission line designed to export all of the power from the generating state to load in another state, demonstrating need and public interest can be problematic for the exporting state.

A few possible solutions to this dilemma were noted, but may be limited in their potential application. In the case of a "cross-over" transmission line, regulators may be able to consider in their decisions the potential for in-state interconnections that will enable the line to serve future state needs. In decisions regarding an export transmission line, regulators may be able to consider several factors: whether the line serves the public interest because of benefits from in-state generation, such as jobs and economic development; the value to ratepayers of transmission wheeling revenue or credits, plus lower costs for wheeling in the future; and the possibility that after the initial power purchase agreement expires the energy could be sold in-state.

The second type of impediment noted by respondents concerns siting and route selection for inter-jurisdictional transmission lines. In this category, respondents mentioned both eminent domain[115] and multiple approvals. When a developer lacks eminent domain authority, a single landowner unwilling to grant an easement can potentially veto a proposed transmission line, force an expensive re-routing or cause significant project delays. Some Western states have delegated eminent domain authority for transmission lines broadly, while other states have limited that authority to public utilities or have written their eminent domain laws in ways that create uncertainty. Developers of interstate transmission lines (or lines across the U.S./Canada border) may find that they cannot obtain eminent domain authority in one or more states or have to litigate the issue in court.

One obvious solution to eminent domain issues was implied by some respondents but not explicitly stated: States could delegate that authority to transmission developers, regardless of whether the

[115] Eminent domain is the inherent right of U.S. state governments to take private land (except within sovereign tribal areas) for a public use without the landowner's consent but with just compensation, and to delegate that right to other entities. In Canada, similar provisions for expropriation of private land and compensation are addressed through federal, provincial and territorial statutes.

developer is a public utility in the state. Although this is a direct solution, it is by no means easy. The tension between the need to exercise eminent domain and the need to recognize individual property rights makes changes to these laws highly controversial. The New Mexico Legislature implemented a tailored solution by creating a Renewable Energy Transmission Authority with eminent domain authority.

Multiple uncoordinated approvals required by local, state and federal agencies is another impediment to transmission line siting. One variation of this problem involves the sometimes overlapping jurisdiction of federal and state/provincial authorities. One proposed solution to this problem is to establish a coordinated "one project, one process" approach through cooperation or formal agreements between federal and state/provincial regulators.

In some jurisdictions, transmission developers must seek separate approvals from local governments. For example, in most Nevada counties, transmission developers must obtain a special use permit from local jurisdictions, and those jurisdictions have discretion to grant such permits. In Utah, transmission developers must similarly seek local government approval in each local jurisdiction through which a proposed line will pass.

To address the problem of multiple siting approvals, some Western jurisdictions have established a single siting authority for transmission lines or a backstop authority that can resolve routing issues that arise when a local government withholds approval.[116] For example, Oregon's process includes the following features:[117]

- Use of specific, statewide standards for determining compliance with siting requirements[118]
- A "one-stop" process in which the Energy Facility Siting Council determines compliance with specific Council standards as well as standards promulgated by other state and local permitting agencies – in other words, the Council makes the decision to issue all permits as part of the site certificate, while ensuring the criteria for issuing such permits remain intact
- Issuance of a site certificate if the proposed facility meets the standards; if the facility does not meet one or more of the standards, the Council may issue the site certificate if the applicant can show that the overall public benefits of the facility outweigh the damage to the resources resulting from failure to meet all of the standards
- Prompt issuance of all permits, licenses and certificates addressed in the site certificate by other state agencies or local political subdivision consistent with the terms of the site certificate
- Public comment periods at the beginning of the process, followed by a more formal contested case proceeding
- Appeal directly to the state Supreme Court for judicial review

Short of these solutions, a centralized information source for transmission developers is a step toward addressing barriers to multiple required approvals.

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[116] For a summary of siting requirements in Western states, *see* James Holtkamp and Mark Davidson, *Transmission Siting in the Western United States: Overview and Recommendations,* prepared for Western Interstate Energy Board, August 2009, http://www.hollandhart.com/articles/Transmission_Siting_White_Paper_Final.pdf.
[117] *See* http://www.oregon.gov/ENERGY/SITING/process.shtml.
[118] If uniform standards apply throughout the state or province, it is less likely that local governments would withhold approval in the hopes that a line will be re-routed.

Cost recovery processes for inter-jurisdictional transmission lines also are impediments to transmission development, according to nearly half of the government officials interviewed. Among the cost recovery issues raised are procedures for utility requests for transmission cost recovery, how regulators determine whether a transmission line is "used and useful" to ratepayers, how regulators determine the economic benefits of a proposed transmission line, and timing of cost recovery. Some regulators interpret used and useful requirements in a manner that would allow costs for new transmission lines in retail rates only for the portion of the line that is immediately needed. This interpretation discourages utilities from building a transmission line in anticipation of future need.

Other policies also can impede development of interstate lines. In Wyoming, a new tax on wind turbine generation will take effect in 2012. To the extent the new tax makes Wyoming less attractive for wind development, interest in transmission from the state will be reduced.

Lastly, some respondents noted two types of environmental policies that, depending on the details, may undermine the economics of inter-jurisdictional transmission lines or increase uncertainty. First, if an RPS policy requires or favors resources in the state – either directly or by requiring that renewable energy be delivered or deliverable in real time – in-state generation is more valuable than imported generation. Second, an emissions performance standard for power plants or other greenhouse gas limitations raise concern that the same transmission line that is necessary to bring wind power from Montana to California, for example, also could deliver coal power.

3.10. Transmission for Exporting Renewable Resources

Generally, lines for export rely on the premise that delivering a better quality resource to the buyer – for example, a wind project with a high capacity factor and lower cost per megawatt-hour – can overcome the costs of transmission from a more distant locale. Several proposed transmission projects are designed to export high-quality renewable resources to California and other high-load areas along the way.

Even jurisdictions that are net importers may have seasonal excess hydro generation that is exported to other areas. The same may be true for seasonal excess wind and solar generation.

Utility Views

One utility identified building transmission to export renewable resources as a way to reduce total costs for its own customers given surplus local resources and revenue potential. A second utility voiced support for the idea as it expressed doubts about its viability because of the many variables that prevent large transmission projects from going forward.

Another utility noted two key barriers to developing transmission for exporting renewable resources, despite the utility's own interest in doing so. First, customers and regulators oppose the utility engaging in projects that do not directly benefit ratepayers. Second, regulators approve costs that are reasonably incurred to serve the utility's customers, not someone else's customers. Regulators are reluctant to impose costs on customers where benefits flow out of state.

One utility that is developing transmission for export pointed out that generators are responsible for paying upfront for upgrades to the transmission system. The upfront payments mitigate the utility's risk of nonpayment, and the generators get reimbursed over time through transmission service credits.

Utilities identified several other ways to develop transmission for exporting renewable resources to other jurisdictions:

- A jointly developed project where the utility uses the line to meet its own needs and a merchant developer uses the line for export
- A reliability project that also has the potential for exports
- A utility exporting to California receives cost recovery for the facility under the CAISO tariff
- A public utility uses its low-interest debt to build the line and leases it to BPA, which recovers costs from users and pays for the asset over time

Many utilities have no interest in building transmission to export renewable resources or expressed concerns about the viability of doing so for the following reasons:

- The utility's mission and business model is to serve native load, not export energy.
- Exporting renewable resources out of state may raise the price of renewable resources for the utility's retail customers.
- Diverting capital for a regional transmission project may sacrifice other projects.
- Loads in bordering states are insufficient to incent exports.
- Building transmission is the responsibility of utilities whose loads would be supported.
- State RPS requirements discourage acquisition of resources from other states.

State/Provincial Interest in Transmission for Exporting Renewable Resources
In most states, the framework established for reviewing the public purpose of a proposed transmission facility does not address exporting resources. However, many jurisdictions have express policies to develop resources and transmission facilities for export for economic development purposes:

- Colorado, New Mexico, Utah and Wyoming[119] have state infrastructure authorities that provide bonds to lower the cost of capital for transmission projects that enable renewable energy development in the state.
- British Columbia recently passed legislation[120] intended in part to help utilities build transmission lines for export. The utility would own the transmission assets, but expenditures for the portion of any line attributable to exports are precluded from inclusion in retail rates. The Utilities Commission is charged with determining benefits and costs that would accrue to ratepayers vs. other buyers.
- In Alberta, the AESO directs the transmission facility owner to build a line if it is needed for imports or exports, to the extent merchant developers are not already meeting that need.[121]
- In 2011 Montana adopted House Bill 198 which extended the power of eminent domain to merchant lines, paving the way for Canadian-based Tonbridge Power to take property for the Montana-Alberta Tie Line and NorthWestern Energy to take property for its Mountain States Transmission Intertie.

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[119] *See* http://rechargecolorado.com/index.php/programs_overview/utilities_and_transmission/clean_energy_development_authority/, http://www.nmreta.com/, www.business.utah.gov/ugreen and http://wyia.org/.
[120] *See* http://www.leg.bc.ca/39th2nd/1st_read/gov17-1.htm.
[121] Alberta's energy policy is designed to support the most efficient system – being well-interconnected for two-way power flows – regardless of whether the jurisdiction is importing or exporting power.

- In 2009 Nevada enacted Assembly Bill 387 which, among other things, allows a utility to file a transmission plan with the PUC to expand existing facilities or construct new lines from in-state renewable energy zones identified as having substantial generation capacity but inadequate transmission capacity. The PUC adopted regulations identifying the zones and clarifying the resource planning process.

Ownership Structures for Exports

On the topic of potential ownership structures involving utilities and exporting power, most of the government officials interviewed did not raise any regulatory obstacles to a utility affiliate approach, where the affiliate would have contracts with buyers at the other end of the line. One regulator noted the importance of "ring-fencing" around any utility subsidiary to avoid putting ratepayers at risk. Another regulator cited public backlash from projects that export power to another state. Market power also was raised as a possible concern if utilities build lines as merchant developers.

Some officials are skeptical that utilities would bear the risk of owning lines for export and pointed instead toward merchant developers. One commissioner who favors the merchant approach for transmission development overall noted the benefits to the utility and ratepayers of paying only for capacity needed. Some jurisdictions raised concerns about unused capacity tied up in contracts on existing transmission lines that could be more fully used if business practices were refined to do so.

Some regulators believe joint ownership between a utility and a merchant developer is a good model. They cited the ability to right-size lines and reduce the environmental footprint of transmission projects, as well as merchant developers' higher appetite for risk that can propel interstate projects forward. For example, NV Energy and LS Power[122] are jointly building the 500 kV One Nevada (ON) Line transmission project to link the northern and southern portions of Nevada and allow sharing of about 600 MW of resources between these areas. Under this hybrid approach, a utility can seek cost recovery for its portion of the line through traditional means, and the merchant developer can seek higher returns to fund the portion of the line for export.[123]

Cost Recovery for Transmission for Export

Regarding cost recovery for lines developed in part for exporting resources, state PUCs rely on the "used and useful" test; costs allowed in the utility's retail rates are proportional to the utility's use of the line to serve native loads. For jointly owned transmission projects, the importing utility would pay for its share of the line, with the local utility paying for the portion of the line serving native load.

Most PUCs cannot consider economic development benefits in determining recovery of utility investments through retail customer rates. Instead, costs included in retail rates are limited to more direct benefits to ratepayers, such as reliability.

Multi-state utilities pose unique challenges in allocating transmission costs. For example, while PacifiCorp has an agreement among some of the states it serves for sharing costs that provide benefits to its retail customers system-wide, individual states may question the timing and proportional share of benefits for their customers, as well as the need for the line to serve native load.

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[122] The U.S. Department of Energy provided LS Power with a loan guarantee for the project.

[123] The ON Line project is the first phase of the Southwest Intertie Project (SWIP). LS Power is building a southern extension of the ON Line project and is proposing a northern extension, as well. SWIP is envisioned to ultimately carry about 2,000 MW of electricity from wind and solar resources in Wyoming, Idaho and Nevada to Southwest and California markets.

NV Energy Renewable Transmission Initiative
NV Energy is assessing interest by renewable energy developers and load-serving entities for transmission service from renewable energy zones in Nevada to other markets, particularly California and the Desert Southwest. The initiative is intended to facilitate the development of renewable energy projects by bringing together interests in transmission projects that would otherwise not be viable to serve individual parties. The developers or end users of the transmission lines would pay their pro rata costs for the lines. NV Energy will gauge whether there is sufficient interest in building lines to transport renewable energy out of the state and, if so, whether to construct them.

3.11. Institutional Structures and Processes

Utility Views on Sufficiency of Institutional Structures to Develop Transmission
Utilities were asked whether the West has the necessary institutional structures to successfully develop transmission to WREZ hubs. Most utilities said an adequate institutional structure already is in place or can be successfully adapted. As supporting evidence, several utilities pointed out that significant transmission projects are underway and institutional structures are evolving to meet changing needs.

One utility pointed out that lines are built based on a combination of need and willingness to pay. That is, the entity that needs a line builds and pays for it, and if more than one entity is involved, each one benefits from a project in proportion to its financial contribution. Similarly, another utility expressed a preference for transmission lines that are driven by sponsors from the bottom-up, based on common goals, rather than a top-down approach.

Several utilities noted that while subregional planning groups are still fairly new, they are off to a good start. One of these utilities sees subregional planning groups as neutral entities that can help drive valuable projects forward.

Despite finding the institutional structure adequate to support development of transmission to WREZ hubs, several utilities expressed concern about uncertainty over policies that might affect the build-out. One utility emphasized that planning approaches for renewable resources are not in sync with each other. For example, while regional transmission planning considers alternative scenarios for meeting California's renewable energy requirements, the state restricts out-of-state resources and plans to expand local distributed generation. Another utility pointed toward lack of stable regulatory policies on environmental regulations such as carbon pricing that would drive renewable resource and transmission development. A third utility explained that the West has valuable forums for planning, but ultimately the problem is securing financial commitments for projects. Higher RPS requirements could drive demand for renewable resources and help secure funding, according to the utility.

Another utility said state-required planning processes are designed to develop the most economic renewable resources. Ultimately, the utility said development will be driven by need, which can be established through top-down requirements such as an RPS.

On the other hand, some utilities believe that changes are needed to build transmission to WREZ hubs, especially long, interstate transmission lines – a clear long-term signal on environmental priorities such as carbon regulation and regional coordination of market functions.

Additional Institutions or Processes Needed – Utility and PUC/Energy Ministry Views
Utilities and government officials were asked whether the following mechanisms are needed to build transmission to WREZ hubs.

Subregional or regional planning for renewable resources. Generally utilities do not believe coordinated planning for renewable resources is necessary, beyond work in subregional and regional transmission planning forums. However, one utility said broader-level resource planning may be particularly useful if significant levels of renewable generation are slated to be built at the same time, in order to identify partners to spread the development risk for resources that may not be needed all at once.

Some utilities pointed out that planning is not a primary driver for developing WREZ hubs. Instead, regulatory certainty is pivotal for the market to develop the most economic resources to meet policy goals. For example, if the public policy goal is to reduce carbon, there needs to be certainty with respect to carbon regulation.

Turning to interviews with government officials, generally all of them support exploring the idea of subregional or regional planning for renewable resources or do not object. One regulator said “It’s necessary given where the wind blows versus where the people live.” Another suggested that planning for renewable resources be considered in tandem with subregional transmission planning. A third regulator expressed interest in a facilitated discussion among states on a “renewable resource development blueprint” for a particular subregion that would make the most sense if jurisdictional lines were erased.

Several government officials said they are waiting to see how WECC’s 10- and 20-year plans address transmission to renewable resources and whether the plans will have any effect.

Regional cost allocation processes. Utilities agree that cost allocation is a difficult issue in developing cross-jurisdictional transmission lines, but do not agree on how to address it. There was no interest in cost allocation on an interconnection-wide basis among government officials interviewed. Following are detailed responses.

Several utilities support the idea of regional cost allocation for transmission. One utility said it is necessary to develop transmission to WREZ hubs. Another explained that an RTO would be needed to secure cost allocation, as it is unlikely the states would establish a way to allocate costs for multi-state transmission projects or that the federal government would do so. One utility found that regional cost allocation is reasonable for resources that can supply regional needs, but that cost allocation must be justified by need based on criteria such as reliability and load. One utility suggested cost recovery mechanisms for stranded costs and Construction Work in Progress as more important than regional cost allocation.

Others expressed concern over their customers paying for a line that does not benefit them directly, finding that the cost-causer pays model works well.

Some utilities feel that Western states simply are not ready to move from a market-based or state-approved allocation model to one that allocates costs regionally. One multi-state utility noted that the cost allocation model for its own projects is challenging. If the region is to move towards a regional cost allocation model, it will need to ask questions such as: What infrastructure should be built? Who will pay for it? What types of development does the cost allocation model encourage utilities to undertake?

Several utilities expressed concern over FERC's Notice of Public Rulemaking on transmission planning and cost allocation.[124] One utility believes the proposed rule would impinge on how utilities in the West allocate costs – based on who directly benefits. Allocating a portion of the cost of a line where there is an assumed benefit, based on some other method, is something that the utility cannot support. Another utility expressed a similar concern over shifting costs to all potential beneficiaries, rather than cost-causers.

Several utilities pointed toward CAISO's cost allocation model, which sets a regional rate for high-voltage transmission, spreading the costs among all retail customers. One utility noted that some municipal utilities opted out of this cost allocation framework, preferring to retain their own cost allocation structures. Another utility said such socializing of costs would be complicated to achieve across balancing areas, it would be highly controversial, and ultimately it would be best to have utilities agree upfront on how to allocate the costs of a project.

Finally, some utilities see cost allocation as a broader issue that should be determined at a higher level. One utility that supports regional cost allocation said some form of federal cost-sharing should be in place if there is a benefit to the nation to invest in renewable resources. Another utility said cost allocation decisions ultimately are political. If certain transmission projects are deemed necessary for public policy reasons, politicians should develop a regional cost recovery process.

Government officials interviewed were decisive: There was no interest in broad regional cost allocation. Most officials said individual states will work out appropriate cost allocation for worthy interstate projects. Respondents cited two examples of regional cost allocation methodologies in the West: PacifiCorp's multi-state protocol[125] and NTTG's Cost Allocation Committee principles.[126]

A couple of jurisdictions believe cost allocation processes at the subregional level would be useful if states could agree on resource areas of common interest. Among the barriers cited: the current economic downturn, different governance over the PUC in each state, turnover among commissioners and obstacles to binding future PUCs.

According to one commissioner, developing common principles for cost allocation is not difficult, but allocating costs for actual projects is challenging.

<u>Regional transmission authority</u>. While most utilities expressed strong reservations or opposition to the idea of a regional transmission authority, a few cited potential benefits. One utility said a regional

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[124] 131 FERC ¶ 61,253, Docket No. RM10-23-000, Issued June 17, 2010, http://www.ferc.gov/whats-new/comm-meet/2010/061710/E-9.pdf.

[125] *See*, for example, Oregon PUC Order No. 11-244, July 5, 2011, http://apps.puc.state.or.us/orders/2011ords/11-244.pdf.

[126] *See NTTG Cost Allocation Principles*, May 28, 2007, http://www.google.com/url?sa=t&source=web&cd=2&ved=0CB4QFjAB&url=http%3A%2F%2Fnttg.biz%2Fsite%2Findex.php%3Foption%3Dcom_docman%26task%3Ddoc_download%26gid%3D193%26Itemid%3D31&rct=j&q=NTTG%20Cost%20Allocation%20Committee%20principals&ei=vSthTojRItPXiAL44-y3Dg&usg=AFQjCNGKpuXMJEm8R9mvXFf6ogaNtXWE0A&sig2=LmuNwByKRJv3BQ5uA6D-mA&cad=rja; NTTG *2008-2009 Biennial Plan Cost Allocation Committee Final Report*, approved Dec. 8, 2009, http://www.google.com/url?sa=t&source=web&cd=1&ved=0CBYQFjAA&url=http%3A%2F%2Fnttg.biz%2Fsite%2Findex.php%3Foption%3Dcom_docman%26task%3Ddoc_download%26gid%3D910%26Itemid%3D31&rct=j&q=NTTG%20Cost%20Allocation%20Committee%20Final%20Report&ei=9yphTqXEIebfiALe1eylDg&usg=AFQjCNFQ7BMIjzDP2-nKbbfFtorvL11pfA&sig2=EVa7dxvRDdeRd2-ex6X_iQ&cad=rja.

authority is needed to create a regional market, which is essential for establishing regional cost allocation to develop transmission to high-quality renewable energy areas. A couple of utilities said a regional authority is needed to coordinate between states in order to serve regional needs and to facilitate siting of transmission lines based on regional plans. However, one of these utilities noted that it is unlikely states will cede siting authority to a regional organization.

Utilities commented on the Northwest's past efforts to create an RTO, noting that the diverse regional interests that prevented its creation remain in force today, including entities that are not FERC-jurisdictional. Cost for creating a regional transmission authority was raised as another significant barrier, particularly that the cost may not outweigh the benefits. One utility said it opted out of participating in CAISO because of the cost.

Some utilities simply do not see a need for a regional transmission authority. They don't see clear benefits over current planning activities and structures in the West, or they have not had issues developing transmission under the current framework.

A couple of utilities raised concern about putting an agency in charge of determining which lines should be built, arguing that it is important to let the market work. Moreover, they are concerned that a regional transmission authority might call for projects that raise rates, but are not necessary to meet reliability or economic needs.

State officials interviewed generally are opposed to establishing a regional authority that can require transmission lines to be built. Some officials noted that much of the transmission in the West is developed by federal power marketing agencies that already take a regional view. In addition, multi-state utilities and merchant developers are building interstate lines.

Other institutional reforms. Several utilities pointed to RTOs in other parts of the U.S. as models for developing transmission to WREZ hubs. Other utilities pointed to institutions in the West that could facilitate renewable resource and transmission development, including federal power marketing agencies and centralized state siting authorities, specifically Oregon's Energy Facility Siting Council and California Energy Commission's siting of solar thermal projects.

Among government officials interviewed, some pointed toward the Southwest Power Pool (SPP) as a potential model that may be helpful in crafting Western solutions to renewable resource and transmission development concerns. In particular, one commissioner pointed out SPP's governance, cost allocation methodologies, and ancillary markets for wind integration as positive role models. Another jurisdiction pointed toward market structures in Texas.

Many regulators interviewed acknowledged that some consolidation of balancing authorities, or at least functional coordination, is necessary. Some regulators pointed toward specific functions of RTOs, such as economic dispatch, that they may be interested in considering in the future.

Regulatory compacts or voluntary compacts between states were cited as a potential vehicle for developing new institutional structures and processes. According to one commissioner, a multi-state compact could encourage utilities to invest in interstate transmission lines.

Government officials provided the following additional ideas for institutional reform in the West:

- An agreement among Western states to procure renewable resources at least cost, in lieu of each state's own economic development interests
- A regional financing authority for entities wishing to build transmission
- A regional authority to remedy the "fragmented siting and approval process" in place today
- A quasi-governmental regional entity that could facilitate siting and resource plan review
- An "environmental payment" included in the cost allocation methodology for intermediate jurisdictions that bear the burden of transmission lines without much in the way of benefits
- Refining identification of lands that jurisdictions consider off-limits to development[127]
- Assistance from BPA and WAPA to right-size transmission lines
- Federal financing of interstate power lines – what some commissioners consider "a public good"
- Development of a regional Energy Imbalance Market[128]
- Better use of existing transmission lines
- Elimination of subsidies, with electricity prices based solely on the true of cost generation and transmission

[127] Citing related problems for the WREZ initiative.
[128] One commissioner called the Energy Imbalance Market concept a solution without big risks or costs or ceding jurisdiction or autonomy.

Chapter 4. Exploring Coordinated Development of WREZ Hubs

This chapter summarizes utility, PUC and provincial energy ministry views on prospects for development of jointly owned resources, joint or coordinated resource solicitations, and other models for developing resources in WREZ hubs, potential benefits and barriers, and conditions that aid cooperation among utilities and jurisdictions. Also presented are views on the potential role of subregional transmission planning groups and possible subregional planning for renewable resources to support development of WREZ hubs. Next is a discussion of regulations that affect the outlook for coordinated development, as well as flexibility of states and provinces to consider long-term renewable resource needs and to broadly consider the public interest and regional benefits. The chapter concludes with potential partners identified by utilities for resource procurement and transmission.

4.1. Relevance of Collaboration Today

Utilities collaborated on building many of the coal and nuclear plants and transmission in the West. Generation examples include the Palo Verde, Colstrip, Bridger, Navajo, Four Corners, San Juan and Intermountain projects. Transmission examples include Palo Verde, Navajo, the AC and DC Pacific Interties, Southwest Power Link, San Juan to Vail, Colstrip line, Intermountain Power Project DC lines, Mead-Phoenix and Mead-Adelanto.[129]

Utility Views

Utilities generally agree that the collaborative model they relied on to build many power plants and transmission in the West is relevant today and the benefits remain the same. At the same time, many utilities expressed reservations about collaborating with others, particularly on renewable resources.

Most utilities that mentioned involvement with joint development and ownership of resources[130] and transmission said it was a positive experience. Some utilities mentioned joint development discussions taking place. One utility noted potential partnerships with independent power producers. Several utilities cited the federal power marketing agencies – BPA and WAPA – as key to large projects involving utilities in multiple states.

Among the drivers cited by utilities for joint development and ownership are projects that are highly capital-intensive, projects so large that individual utilities do not want to take all the risk themselves, projects with technology risk, and capturing economies of scale and reducing cost by scaling up project size beyond what an individual utility needs. Other factors raised are aligning with multi-state transmission projects, facilitating right-sizing of lines and supporting cost allocation processes.

At the same time, utilities cited unique features of renewable resources that make it unnecessary or difficult to consider joint or coordinated procurement, as well as particular challenges for resources distant from loads. Unlike large thermal plants, renewable resource development is modular and can achieve economies of scale at relatively low installed capacities. Utilities said they were capturing economies of scale in the tens of megawatts for solar facilities and at around 100 MW for wind.

[129] All of these are interstate lines except Palo Verde. Source: Rob Kondziolka, Salt River Project.

[130] Among the projects mentioned are the recently completed Harvest Wind Project, co-owned by Eugene Water & Electric Board (EWEB) and three consumer-owned utilities in Washington, and the Foote Creek I wind project built in 1999 and co-owned by PacifiCorp and EWEB.

Renewable resources also have different operating characteristics than thermal plants, potentially complicating resource sharing.

Utilities expressed exceptions to the general view that renewable resources are better developed by individual utilities. First, some utilities said large concentrated solar power and geothermal projects may be similar to coal or nuclear projects, where a utility partnership reduces risk exposure and helps reach critical mass for facility size for more economical development and operation. Second, new technologies such as wave energy pose risk that may best be shared across a group of utilities. In addition, if utilities develop resources in WREZ hubs far from load centers, cooperation in building out resources in these areas makes sense, according to some utilities.

Utilities also noted the predominance of projects developed by independent power producers as a factor in the viability of the cooperative model for renewable resource development. Where independent power producers are involved, utilities find less room for cooperation among themselves. However, one utility suggested that instead of developing projects jointly, utilities should cooperate on securing a power purchase agreement big enough to achieve a lower price for everyone.

Most utilities feel comfortable with the general concept of coordinated resource procurement if it's the right project in the right place, at the right time and at the right price. Timing issues in particular were seen as significant, including aligning resource planning and procurement cycles with other utilities, especially those in another state.

Some utilities viewed joint or coordinated procurement like any other bilateral discussion: If there are areas of common interest among parties with value for their customers and shareholders, it could lead to joint development, collaborative procurement or sharing of existing generation. Most utilities said there are no institutional barriers to joint or coordinated development if the resource is the best fit for their needs; state regulations are sufficiently flexible to enable such collaboration.

According to many utilities, developing capital-intensive transmission and addressing integration for variable energy resources have greater potential for cooperation than renewable resource procurement. Utilities cited cooperation on new lines to access renewable resources, as well as subregional planning groups that have sparked interest in joint transmission projects.

PUC/Energy Ministry Views

Jurisdictions generally believe that the collaborative model utilities used effectively for decades to develop large fossil-based generation and associated transmission in the West has at least some transferability for developing WREZ hubs. However, they say this model has not been much applied to renewable resource development in part because of differences in capital, scale, and perceived risk of large fossil-fuel facilities versus typical renewable energy projects.

In support of collaboration, jurisdictions point toward the attractiveness of spreading cost and risk across multiple parties, particularly for transmission lines that traverse jurisdictions. Simply increasing financial, political and intellectual clout in resource and transmission planning processes can be useful, according to one regulator.

While some jurisdictions believe that more proactive regulations may be required to spark utility collaboration, most regulators believe that utilities need to drive these efforts. In addition, some regulators prefer utilities to enter into power purchase agreements, rather than own generating facilities. One such regulator suggested that utilities collaborate as off-takers for a project that independent developers cannot advance on their own. In Alberta, where utilities do not procure long-term resources, joint ventures among independent developers for renewable resources are commonplace.

One regulator cautioned that utility collaboration should not bypass competitive solicitations, especially considering that independent developers have acquired many of the best wind sites. Another regulator said variable energy resources (wind and solar) may pose more operational issues for joint ownership compared to baseload renewable resources (geothermal and biomass), at least until ancillary service markets are further developed to address integration needs.

The collaborative model may not be of interest to states with low loads and access to quality renewable resources locally, according to a regulator in such a state, except to spark discussions on export opportunities.

Consistent with utility interviews, some jurisdictions noted the important role that BPA and WAPA can play in facilitating utility collaboration, including financing, transmission development and eminent domain.

4.2. Benefits of Joint or Coordinated Resource Procurement

Utility Views

Utilities articulated a range of benefits for joint or coordinated procurement of renewable resources from WREZ hubs. The most commonly identified benefits were reaching economies of scale, spreading cost and risk, sharing information, diversifying resources, and leveraging differences in timing of resource output and load profiles across utilities. Several utilities said coordinated procurement would help them identify and access areas with high resource potential and least-cost resources.

According to one utility, "The more players you can get involved, the more it brings down the cost for everyone." Another noted that scaling up project sizes through coordinated procurement may yield cost savings on operation and maintenance. However, a Southwest utility said it can get economies of scale on its own from relatively small, local solar resources. A remotely located project would have to be far lower cost than local resources in order for it to be attractive to the utility. In addition, local solar resources are so vast that the utility does not expect to run out of them. On the other hand, some utilities mentioned the potential of utility coordination to foster export from resource-rich regions to distant load centers.

A consumer-owned utility in the Northwest flipped the economy-of-scale issue on its head. Harkening back to the Washington Public Power Supply System nuclear debacle,[131] the utility raised concerns about developing large-scale renewable energy projects and transmission, instead of expanding resource development in a modular fashion.

While conceding that multi-utility projects may have advantages for cost *recovery*, one large utility said cost *allocation* remains an issue and the project would still have to stand on its merits in each state. "How each state evaluates it is all that matters," the utility said.

[131] *See* http://en.wikipedia.org/wiki/Energy_Northwest.

Utilities linked cooperation on renewable resource development with more effective transmission planning. First, it would allow transmission planners to factor in broader generation plans when designing and sizing transmission lines, including interaction of wind and solar resources with different diurnal patterns of production. Second, it would help coordinate transmission access to resource-rich areas. Third, it would help ensure transmission projects do not negatively impact each other when utilities develop resources in a common area.

One utility saw value in letting bidders know where they stand in multiple utility solicitations at the same time.

PUC/Energy Ministry Views
To the extent utilities are able to coordinate to access high-quality renewable resources in a common area, regulators see the following advantages:

- Achieving economies of scale that are not possible otherwise, driving down the cost of renewable energy and facilitating development of transmission lines to least-cost sites that utilities otherwise would not be able to reach
- Attracting developers capable of financing large-scale projects
- Acquiring more diverse resources
- Tying isolated portions of the Western grid together
- Building out the Western grid in a more efficient manner
- Right-sizing transmission lines
- Revealing common resource and transmission needs in a similar timeframe
- Developing the best resources, regardless of jurisdictional boundaries
- Learning from other state officials about siting issues
- Working on a cluster of projects altogether to address transmission needs
- Keeping down development and environmental costs for projects in close proximity to one another

4.3. Barriers to Cooperation

Utility Views
As discussed above, several utilities pointed out that the drivers for large, jointly-owned thermal power plants are not necessarily applicable for renewable resources, which typically are small and developed in a modular fashion. That's particularly the case for large utilities with sufficient demand by themselves. Another overarching issue heard in the interviews is that some utilities have sufficient renewable resources within or close to their service area to meet needs for the foreseeable future – say, over the next decade.

Transmission was another primary issue raised. First is the cost associated with transmission to remote WREZ hubs – the level of investment, as well as cost allocation among participants and cost recovery from retail customers. Second, it takes far longer to develop transmission than to develop renewable resources, requiring a commitment to transmission before associated generating facilities can be built. If long-term, coordinated planning could help address that problem, such efforts would be valuable. In addition, approval for interstate transmission lines is done in a state-by-state piecemeal fashion, increasing risk to the utility. Further, some utilities do not even consider resources where transmission is not currently available.

An additional, central issue raised is whether wildlife and other environmental issues will prevent WREZ hubs from being developed in an affordable manner, even with joint utility efforts. Another concern is that NIMBY[132]-ism poses a significant barrier to siting, permitting and rights of way.

While some utilities see value in coordinating resource procurement from WREZ hubs, they say concrete commitments require shared needs and interests, a framework for developing renewable resources for export to distant load centers, and in some cases stricter renewable energy standards or carbon regulations. One utility noted that it is difficult to find a nexus of utility need and state policy to spur group procurement of resources. To the extent policies require self-sufficiency of supply within a jurisdiction, or state RPS requirements include a preference for generation from local sources, there is no driver for utilities to partner with an entity outside the jurisdiction.

Some utilities noted that self-determination is important to them. In addition, different project elements are important to each utility, and utilities view operational issues differently. Many utilities pointed out that they would prefer to do things on their own if they are able to do so. One utility experienced in joint development and ownership said it goes down that road if it is the only way to get the project done. That may be the case if a utility is capital-constrained, when it needs partners for large facilities because of the sheer scale of the project or to achieve economies of scale, or when it deploys a technology that is not fully commercialized – for example, wave energy today and the early days of wind. Some utilities said the dry hole risk for geothermal also may be a reason for joint development.

Even once utility partners are identified, several utilities pointed toward the difficulty of keeping partners on the same page. And the more parties, the more challenging it is to get the deal done. Challenges remain after the plant is built. One utility sold its share of a power plant with multiple owners for lack of a common outlook on how to operate the plant.

Following are other barriers that utilities said inhibit coordinated development of WREZ resources:

- RPS policies vary by state, and future RPS requirements are uncertain, making large-scale acquisition of remotely located renewable resources risky.[133]
- Federal incentives for renewable resources are not certain over the timeframe needed.
- FERC's policies regarding open access and standards of conduct make it difficult for utilities to coordinate build-out of transmission and resources, due to limitations on communication between transmission and merchant functions within utilities.
- State competitive bidding requirements for resources can make joint utility acquisition difficult.
- The cost of integrating large volumes of renewable resources and lack of dispatchability are concerns, particularly with fragmented balancing authorities and insufficient ancillary service markets.
- Solar and wind resources have a low capacity factor and, under current transmission pricing schemes, a high cost of delivery.
- Large-scale build-out of variable energy resources increases instability and reduces reliability of the transmission system, according to a couple of utilities.

[132] Not in my back yard.
[133] California RPS policy was singled out by several utilities as a barrier to development of renewable energy and associated transmission from other states, both because of its in-state requirements and complex rules that make it difficult for external suppliers to deliver energy to California with firm transmission.

- Coordinating procurement means individual utilities would lose relative competitive advantage of being first in the market.
- Developing large resources in a concentrated area could diminish geographic diversity and exacerbate balancing issues for wind and solar.[134]
- Geography may make joint projects difficult, because each utility must provide transmission to its own loads.
- Utilities may meet RPS requirements just in time, even with liberal banking provisions for renewable energy credits. Developing WREZ resources in advance of RPS target dates could raise concerns about used and useful requirements.
- Consumer-owner and investor-owned utilities have different missions and tax treatments and may not want to work together.
- Municipal utilities may be difficult to work with because their review processes tend to be lengthy, frustrating business partners.

PUC/Energy Ministry Views

Government officials interviewed cited the following barriers to multi-utility collaboration, particularly as it relates to interstate transmission lines:

- In siting and cost recovery proceedings, it is difficult to demonstrate the need for and benefit from a transmission line for the state's residents, or more narrowly for the utility's ratepayers.
- Merchant developers, not utilities, should build transmission that will be used for export.
- There are insufficient off-takers for large amounts of power.
- Poor economic conditions and lack of load growth, including impacts of energy efficiency programs, reduce resource needs.
- Resource policies vary – states that want to develop local resources versus states that want to export resources, and states that need additional resources to meet portfolio standards versus states that have no such standards or already are well-positioned to meet current targets.
- Pancaking of transmission charges leads utilities to acquire resources close to their service areas, even if they are lower quality.
- Without a champion for a particular WREZ hub, it is unlikely to be developed.
- It is difficult to align timing for permitting, resource development and transmission.
- Utilities are focused on meeting near-term load growth and reliability needs, not long-term societal benefits.
- Firming is not provided at the source – for example, near wind sites – reducing the attractiveness of remote resources.
- Residents do not want energy or transmission facilities in their back yards.
- Future air pollution and carbon regulations are uncertain.
- Anti-trust concerns may be raised when utilities negotiate with one another.[135]
- Utilities have differing resource requirements and risk tolerances.
- Lengthy environmental impact statement processes result when federal agencies are involved, either directly through BPA's or WAPA's participation or indirectly through federal funding.
- Utilities want to maintain market power.

[134] Conversely, some utilities noted that developing WREZ hubs could add diversity to their resource portfolio in terms of types of resources and output profiles.
[135] One commission said it issued a waiver for its utilities on anti-trust issues for carbon capture and storage facilities for coal plants.

- Utilities fear lack of control when multiple partners are involved.
- For Alberta, barriers to cross-border joint ventures include capacity payments (antithetical to the AESO market) and subsidies in the U.S., as well as requirements that slow down the contracting process – for example, processes requiring approvals and waiting on queues.

Barriers to Joint Ownership With an Out-of-State Utility
Generally, government officials interviewed do not see any major barriers to joint development by utilities in different jurisdictions. However, they expressed the following concerns: 1) the utility would have to demonstrate the project was low risk; 2) choice-of-law clauses[136] are problematic for joint development between U.S. and Canadian entities; 3) FERC would review any implications that joint utility ownership may have on market power; and 4) a large utility might enter into a joint development agreement with a small utility and take all of the benefits for itself, using the other utility as a façade.

4.4. Conditions That Create Multi-Utility Cooperation

Utility Views
According to utilities, by far the strongest condition that can help create multi-utility cooperation for renewable resource development and transmission is potential for shared benefits – spreading capital costs and risks, achieving economies of scale, sharing excess capacity, complying with renewable resource mandates, meeting load and supporting system reliability.

Some utilities said that if there is a strong business case for developing WREZ hubs and associated transmission, utilities will cooperate. One utility said an objective study based on sound assumptions showing the differential price of renewable energy delivered from these areas, compared to local resources, could serve this purpose.

Utilities also see top-down political pressure as important – for example, a memorandum of understanding (MOU) between governors with clear statements of priority for renewable resource development. Synchronizing renewable energy standards across states also is considered key, including common definitions for qualifying renewable energy credits and reducing barriers to acquiring out-of-state resources. Regulatory orders play an important role in supporting cooperation as well, utilities say. In addition, a streamlined permitting process and harmonizing siting requirements can facilitate multi-utility cooperation. Other suggestions included instituting a multi-state process that allocates costs for transmission and securing support from multiple PUCs for cost recovery for joint utility projects.

PUC/Energy Ministry Views
State PUCs and provincial energy ministries said the following conditions would facilitate multi-utility collaboration:

- Concurrent resource and transmission needs – a critical mass of the willing
- A stable regulatory framework, from environmental regulations to cost recovery
- Regulators directing utilities to consider opportunities for collaboration and making it an issue in cost recovery proceedings
- Aggressive RPS or carbon requirements that create a compelling environment to develop vast amounts of renewable resources

[136] Provision that specifies which jurisdiction's laws will govern any disputes related to the contract.

- State or FERC incentives for utilities to collaborate, if there appear to be substantial savings (using FERC's bonus return on equity, for example)
- Governors and business groups making the case that transmission lines for renewable energy are necessary for economic development
- PUCs broadly interpreting state statutes on need for transmission and benefits for state residents and ratepayers
- Common rules across jurisdictions regarding what types of projects and benefits can be considered
- High capital-cost projects and projects with technology or other unique risks
- Need to collaborate for financing on a large project
- Small utilities that need to collaborate with one other or with a larger entity
- A large, attractive project that requires more than one off-taker
- Siting cooperation across jurisdictions

4.5. Conditions That Create Multi-Jurisdiction Cooperation

Utility Views
There was no broad consensus among utilities on conditions that might lead to multi-jurisdiction cooperation on development of renewable resources and transmission. Rather, utilities cited a range of viewpoints.

Several utilities noted the importance of involving state utility regulators to secure multi-state cooperation. One utility said that unless regulators are involved, any higher-level attempts to stimulate development of renewable resources and transmission will be limited. Another utility said PUCs should work together on approving large projects.

A number of utilities suggested that governors could play a key role in supporting multi-state cooperation. One utility suggested bringing governors together to try to harmonize state RPS provisions, at least to establish common terminology for concepts such as qualifying resources and renewable energy credits. Another utility suggested that more is needed than governors signing MOUs; someone in each governor's office must be designated to coordinate with utilities and lead efforts for multi-state cooperation. WGA is seen as a good platform for multi-state dialogue, in particular to find common ground on ways states could complement each other's resources and needs.

One utility suggested that the answer to multi-state cooperation is continuation of the current process whereby utilities identify mutual interests and figure out how to work together. WECC's interconnection-wide planning process, with involvement of PUCs and state energy offices, is seen as a potential vehicle for multi-state cooperation. Demand for renewable resources also is important in stimulating multi-state cooperation, according to the utility.

Several utilities believe cooperation among states will be difficult. First, they view states that limit RPS compliance to in-state generation as effectively blocking multi-state cooperation. Second, some utilities believe states are unlikely to objectively establish a set of benefits that could flow from cooperative development because of parochial interests.

PUC/Energy Ministry Views
Following are conditions that create multi-jurisdiction cooperation, according to the government officials interviewed:

- Multiple jurisdictions that see benefits of a project for their own state or province
- A stable regulatory framework, including certainty over states' appetites for out-of-state resources
- Harmonized approval processes and timelines for siting cross-border projects
- Utility regulators who believe renewable energy and transmission development that benefits the region as a whole will ultimately benefit their own state
- Participation of utility regulators in subregional planning groups, including cost allocation discussions
- State and provincial leadership to craft common rules on qualifying renewable resources and tradable renewable energy credits to enable broader markets in the West, including reciprocity agreements[137]
- Federal designation of transmission corridors – if states have a strong voice in the process
- WECC interconnection-wide planning and Western governors' support of the findings
- Continuing regional collaborations, such as the SPSC and CREPC
- Discussions involving state PUCs, siting councils and energy offices in two or more states that address IRP, siting and related energy issues for a WREZ hub of common interest
- Interstate compacts, MOUs, PUC to PUC dialogues, and discussions between legislators in two or more states
- Cost allocation schemes that enable utilities to invest in transmission
- Multi-state planning initiatives

4.6. Potential Role of Subregional Transmission Planning

Following are perspectives of utilities, state utility regulators and provincial energy ministries on the role that subregional transmission planning could play in coordinating development of WREZ hubs.

Utility Views
Most utilities say subregional transmission planning can help facilitate potential partnerships for developing WREZ hubs and associated transmission. Besides the value of information exchange alone, subregional planning groups can provide a forum for utilities to identify shared interests and needs and, if commonalities exist, to partner on projects. Similarly, these groups can help identify a resource area of common interest and develop transmission plans to access the resources.

Because meetings are open to stakeholders, subregional planning groups bring in valuable information from renewable energy developers on where they are looking to develop resources and where they would like to see transmission. Similarly, open season processes are seen as a valuable avenue for collecting information from project developers.

Several utilities expressed reservations about the extent to which subregional transmission planning can facilitate partnerships to access WREZ hubs. While such planning is useful, it does not alone transform utility plans in favor of renewable resource development. Transmission projects may not get built

[137] *See* Sections 5.1 and 6.2.

because there is insufficient commitment from generators to use the line. Or a utility may find that participating in a large transmission project may not secure least-cost supply for consumers.

Incomplete information poses another barrier to the ability of subregional planning groups to facilitate partnerships. Planning can be stymied by a lack of transparency on projects planned by independent power producers and merchant transmission developers. A couple of utilities said restrictions on sharing information between their commercial and transmission functions can impede cooperation, while other utilities did not find this to be a barrier.

Two other limitations of subregional transmission planning are worth noting. First, there is a trend in parts of the West toward development of smaller renewable energy projects closer to load. These projects are typically faster to complete because they do not require construction of long-distance transmission lines. Second, cost allocation remains a formidable barrier to building transmission to WREZ hubs, according to several utilities.

Many utilities noted that subregional planning groups already are addressing development in WREZ hubs to some degree. Several of these groups, as well as WECC's regional transmission planning process, have evaluated alternative renewable resource locations and the costs of delivered energy associated with these areas. Still, the following utility suggestions indicate there is room for improvement.

First, many utilities agree that subregional transmission planning should make efforts to identify optimal transmission build-outs to WREZ hubs of common interest. Shifting the focus of transmission planning from solving system problems, such as congestion to development of targeted WREZ hubs, is not likely to be an easy task, particularly where transmission planners are concerned with remedying existing operational problems.

Second, subregional planning groups should conduct studies on the capabilities of the existing grid to isolate where transmission additions are needed to accommodate additional renewable resources. Subregional planning groups also should expand information-sharing so participants can better understand where developers plan to build projects, based on information from interconnection queues.

Lastly, several interviewees observed that resource planners do not communicate on a subregional level to the extent that transmission planners do, limiting the potential for information exchange and cooperation. According to one utility, resource planners must be party to subregional transmission planning if the process is to successfully facilitate partnerships on renewable energy development.

PUC/Energy Ministry Views
Jurisdictions generally believe subregional transmission planning has potential to facilitate partnerships for renewable energy development and associated transmission. Most jurisdictions believe that subregional planning groups, at a minimum, facilitate the sharing of valuable information and could stimulate discussions among utilities and developers about tapping resources in WREZ hubs.

Some interviewees went further, stating that subregional planning can lead to MOUs among utilities to jointly pursue transmission development. Subregional planning groups also can support state renewable energy zone processes, such as analyses by Southwest Area Transmission in support of the Arizona Renewable Resource and Transmission Identification Subcommittee process and Biennial Transmission Assessment.

However, planning for renewable resources is not a mission or mandate of the subregional planning groups. Further, they have no authority to direct utilities to build lines. Decision-making between states is needed, in the opinion of one regulator. In addition, entities that are not FERC-jurisdictional are not required to take part in subregional transmission planning, and these entities generally are not state-jurisdictional, either.

PUCs and provincial energy ministries put forward the following ideas as possible next steps for subregional planning groups to foster WREZ development:

- Put WREZ hubs squarely on the table for consideration
- Identify corridors and transmission lines that are necessary for exporting and importing renewable energy across jurisdictions
- Identify anchor tenants, then other generation and load, to reach a critical mass of transmission needs to justify lines
- Increase involvement of state decision-makers, BPA and WAPA
- Plan for transmission over at least 20 years with the goal of achieving long-term carbon reduction goals through joint procurement
- Coordinate with utility personnel that approve resource procurement
- Seek an order from FERC requiring subregional transmission planning to access high-quality renewable resources
- Conduct optimization studies that go beyond WECC congestion studies and simply summing up transmission lines utilities already are proposing
- Direct regulated utilities to submit a request to subregional planning groups to study transmission to a particular WREZ hub
- Provide information to policy makers that demonstrates the benefits of cooperation on developing WREZ resources and, conversely, how balkanization – restricting development to in-state resources – may be counter-productive in the long run

4.7. Subregional Planning for Renewable Resources

Utility Views
Most utilities interviewed believe there is value in coordinating planning for renewable resources on a subregional basis.[138] They noted renewable resource discussions already underway within subregional planning groups, state renewable energy zone and related transmission initiatives, and WECC transmission expansion planning, as well as discussions with neighboring LSEs.

However, utilities identified limitations. Several interviewees said coordination may not be important because renewable resources tend to be smaller scale than thermal resources. Moreover, it may be difficult to find clearly aligned interests to drive cooperation on renewable resource planning, compared to planning for large thermal plants or transmission. Having an abundance of local renewable resources also may limit interest in subregional planning. Lastly, state policies that restrict RPS compliance to in-state resources can limit the scope of utilities for coordinating renewable resource planning.

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[138] Subregional resource planning for purposes of the interviews was defined as planning that involves more than one utility, but that falls short of including the entire Western Interconnection.

PUC/Energy Ministry Views
Jurisdictions are split on whether coordination of renewable generation planning among utilities would have value. Some regulators believe that such coordination would facilitate jointly owned interstate transmission lines to access high-quality renewable resources. Others are skeptical of resource planning beyond a utility-specific basis.

One regulator said that instead of coordinating resource planning across utilities, what's needed is to eliminate siloes *within* utilities regarding resource and transmission planning. Regulators in low-load states that are well-positioned already for meeting renewable resource requirements do not see value in their utilities coordinating resource planning to meet in-state needs. According to another regulator, multi-state utilities already are able to achieve some of the aims of coordinated planning across states and there may be no advantage to going beyond that.

One state regulator said coordinated resource planning could help utilities access sites they can't reach otherwise, to the extent it triggers coordination on transmission development.

Some regulators believe resource planning processes should be coordinated among neighboring utility commissions. One regulator mentioned the potential value of coordinating renewable generation planning in order to address integration issues in the BPA footprint.

While the subject of coordinated generation planning and development among utilities is not directly relevant for Alberta, independent developers enter into joint ventures, and coal plant owners have partnered with wind developers to diversify their holdings.

4.8. Possible Mechanisms for Coordinated Development of WREZ Hubs

Drilling down to specific mechanisms for coordinating resource development in WREZ hubs, utilities generally favor joint development and ownership and are less optimistic about issuing joint solicitations or coordinating separate solicitations.[139] Some utilities pointed out that current regulations for resource planning and acquisition do not anticipate these approaches. Most utility regulators are supportive of pursuing any of these options. Following are utility and regulator reactions to various types of coordination on renewable resource procurement.

Joint Development and Ownership
<u>Utility views</u>. Many utilities said that if the right opportunity arose, they would consider joint development and ownership of renewable resource projects. For example, a utility may be interested in joint development of resources that it does not have easy access to, such as solar with thermal storage.

Most utilities are not developing wind sites themselves. However, they can become a joint project owner if an independent power producer sells a facility to a group of utilities. The facility is typically operated by the independent party to maximize generation, and the utility takes a share of the output.

Utilities that are developing wind sites themselves said they plan to build them out over time to meet future RPS targets. Other utilities have acquired site leases beyond currently anticipated RPS requirements, possibly providing opportunities to coordinate on project development with other

[139] Resource solicitations may result in power purchase agreements or a build-own-transfer agreement leading to resource ownership.

utilities. A large investor-owned utility said it has more development rights than it needs to meet anticipated RPS requirements and may be willing to share those sites with another utility. There also may be potential for utilities to coordinate on new lease acquisitions and on transmission development that would make leases more fruitful.

Joint development may be difficult for utilities whose regulators prefer power purchase agreements. According to these utilities, there is a high bar for demonstrating a utility-owned project has ratepayer benefits contracted resources.

Some utilities said they need PUC authorization upfront to engage in WREZ development activities before considering any type of partnership because of the risk of abandoned plant costs. Going further, several utilities said joint development would require an external stimulus – a regulation, subsidy or some other type of benefit. One utility said it would need confidence that the project was likely to be built to make it worth the utility's time to consider joint development.

Several utilities said they would coordinate on resource procurement only if the resource was very well-priced – for example, if a utility was developing a 500 MW wind farm but only needed 300 MW and was able to sell the balance at a highly competitive price.

Consumer-owned utilities noted that the tax code would need to change in order for joint development to work. To keep costs down as non-taxable entities, they let the project developer own and operate the resource and take advantage of federal and state tax credits and depreciation benefits. The utilities may have an option to purchase the project after those benefits have been exhausted.

Differences in regulation and management philosophies may pose significant barriers. A utility that has been trying to get large solar projects off the ground with out-of-state utilities said discussions have been fraught with issues stemming from divergent contracting, credit and regulatory requirements in each state. Some utilities said joint procurement would be easier with utilities in the same state because they are subject to the same standards.

Some regulated utilities acquire resources on behalf of rural energy associations under wholesale contracts. One such utility said joint development would not work as well with utilities in these associations because they don't want to be encumbered with the regulatory process that investor-owned utilities must follow.

State/provincial views. Jurisdictions universally stated that joint development and ownership is a viable option today and many voiced support for this idea – some strongly.[140] Several regulators noted that joint procurement has been the norm in their jurisdiction for thermal generation and transmission projects. Several states are encouraging joint project development, though they cannot compel it.

Despite this support, most utilities have not conducted joint procurement for renewable resources for reasons discussed elsewhere in this report, including scale of development and a preference for power purchase agreements by some states or on the part of individual utilities.[141]

[140] Questions regarding joint or coordinated resource procurement by utilities are irrelevant for Alberta, where utilities are the suppliers of last resort and use the AESO trading platform to procure resources solely on a short-term basis. Independent developers are free to develop resources jointly with others within or outside the province.

[141] One state regulator observed that for a utility that normally contracts for renewable resources, joint ownership avoids the risk of a downgraded credit rating due to imputed debt.

Many jurisdictions pointed toward pre-construction proceedings that give utilities an early indication of the likelihood of cost recovery, mitigating potential utility concern that jointly developed projects may pose greater risk in that regard. Opportunities include approval or acknowledgment of IRPs or procurement plans, approval of resource solicitations that may include self-build and turnkey options, CPCN applications, review of RPS compliance plans and applications for rate riders.

Among recent examples of joint development is a limited partnership for a jointly developed hydroelectric project between BC Hydro and Fortis, a privately held utility. One state regulator referred to a consortium of utilities considering joint development of a sizable solar trough plant a couple of years ago and the commission's support of the concept.[142] Another state is encouraging utility collaboration on a unique opportunity to develop a large solar project on a brownfield site.

Joint Resource Solicitations

A recurrent theme in the interviews is that utilities considering joint or coordinated solicitations must have similar resource needs in a similar timeframe, and any selected project would have to fit both utilities. All parties also would need to be comfortable with the solicitation document and process, such as the timeline and analysis used to pick winning bids. In order to coordinate development of particular WREZ hubs, utilities would need to narrow the locations where resources are sought. Solicitations today generally do not specify location. One utility noted that specifying a particular area in a resource solicitation might be seen as locking out resource developers that may want to participate but do not have leases in the area.

Some small consumer-owned utilities already procure renewable resources through a joint action agency. Others expressed interest in participating in discussions on joint resource solicitations and said they may reveal that it makes sense to own a portion of a large project, depending on cost. A large municipal utility said partnering is "essential" in order to acquire certain resources at the most economic size.

An issue raised for joint solicitations by utilities in different states is the involvement of separate independent evaluators to ensure fairness of the process in each jurisdiction. The utilities' key concern in this regard is inhibiting progress on timely project acquisition.

One utility raised potentially insurmountable confidentiality issues for joint solicitations, however, it said utilities can work together on resource and transmission development outside such processes. Finally, a few utilities said coordinating resource solicitations may be seen as anticompetitive collusion and trigger antitrust concerns.[143]

[142] Utility interest dissipated with declining solar PV costs.

[143] This issue arose in comments on New England Governors' recommendations for coordinated renewable resource procurement. Northeast Utilities simply raised the potential for anti-trust issues and highlighted "substantial legal challenges" regarding "utility interaction in bid awards" for a Massachusetts resource acquisition process. However, National Grid's comments cited a joint renewable resources solicitation in Massachusetts where each electric distribution company received its own bid responses and proceeded independently in considering the responses, thus mitigating anti-competitive concerns. *See* http://www.nescoe.com/Coordinated_Procurement.html.

Coordinating Separate Solicitations for Resources
A step short of issuing *joint* solicitations is coordinating the timing and potentially the resource locations of interest for *separate* solicitations by individual utilities. In the latter case, a project developer successful in multiple solicitations would have multiple off-takers and contracts.[144]

Utility views. One large consumer-owned utility said coordinated procurement is something it should be doing already with other such utilities in the state. Another such utility said coordinated procurement would make sense if it enabled sizing transmission appropriately and building it on a reasonable schedule. However, a third utility said the solicitation would have to be in an area with existing transmission.

It may be difficult to agree on a power purchase agreement common to multiple parties, according to some utilities. Differing utility credit requirements for counterparties is one aspect where there may not be agreement among utilities.

A multi-state utility pointed out challenges where states have different views on the benefits of power purchase agreements versus utility-owned resources. A couple of utilities mentioned another potential barrier: differences in operational preferences for renewable energy projects, such as curtailments and dispatch requirements (if the resource is dispatchable).

State/provincial views. Most jurisdictions see no major barriers to coordinating procurement across utilities, at least to align the timing of separate utility RFPs. On the other hand, one regulator said the idea is attractive in theory but may be unworkable in practice because of differences in state RFP processes, and it may be unnecessary given the typical scale of renewable energy development.

Some state regulators noted their authority to order coordination of RFPs for the utilities they regulate. Such coordination would have to support development of an interstate transmission line to make the effort worthwhile, according to one regulator. Another, whose state has a small load, believes coordinated procurement is more important for utilities that serve large loads.

In some locales, a change in statute or rule may be required to address alignment of filings for IRPs and RFPs. As one government official put it, coordination of resource solicitations should begin in the IRP process, with utilities demonstrating they are planning for the greater good by consolidating the number of transmission lines needed in the region. Another official pointed out that RFP coordination does not solve the problem of aligning on-line dates for resources and transmission.

The concept of a model RFP document solicited a couple of comments. First, each utility will be looking for particular resource characteristics. Second, it may be difficult to accommodate varying utility practices for addressing risk, including specific requirements for developer credit and damages.

In California, the PUC seeks to drive uniformity in the regulated utilities' long-term procurement plans,[145] including analyzing common scenarios and aligning the timing of submittals and approvals for annual renewable resource solicitations, although closing dates may differ. A procurement review group including representatives of state agencies and consumer groups receives the bidders list and can

[144] In order to finance the project, the developer would need to align the timing of signed power purchase or turnkey agreements or develop the project in stages.
[145] *See* http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/ltpp_history.htm.

comment on all of the utilities' solicitations without sharing sensitive information. The PUC also reviews the utilities' pro forma documents for solicitations, but they are not standardized. Responding to the market's interest in standardized terms and conditions, the PUC at one point required many uniform terms and conditions in the utilities' power purchase agreements. After two years, parties determined that the approach was not working well. There are now only a few contract terms that the utilities cannot modify.[146]

The California PUC also has required solicitations to focus on a particular transmission line – for example, requiring solicitations to seek bids to fill out the Sunrise Power Link. At the same time, the PUC directed that bids in a specific geographic area should not be favored over more cost-effective alternatives in other locations.

Coordinated Renewable Resource Procurement in New England

In September 2009, the New England Governors' Renewable Energy Blueprint[147] directed regulatory and policy officials to review the availability of renewable resources in the region, consider potential mechanisms for joint or coordinated competitive procurement, and report the results to the governors within 12 months. The same month, New England governors and Eastern Canadian premiers adopted a resolution directing officials to identify potential contract structures, pricing mechanisms and regulatory approvals "for the procurement of regional power," including a sample RFP that could serve as a model for future solicitations.[148]

In July 2010, the New England States Committee on Electricity (NESCOE) issued a report on coordinated procurement for renewable resources, including potential mechanisms, terms and conditions, and approaches for regulatory approval processes.[149]

Following up on the report, NESCOE issued a Request for Information for renewable resources that "provided the New England states with a reasonable basis to conclude, preliminarily, that coordinating the states' efforts with respect to the competitive procurement and delivery of such resources may enable the states to achieve their various objectives in a more cost-effective manner than if each state sought to independently satisfy all of their individual clean energy objectives."[150] This process also identified transmission projects in various stages of development that, subject to further analysis, could facilitate the delivery of renewable energy to New England consumers.

A resolution adopted by New England Governors in July 2011 expressed continued interest in exploring the potential for joint or coordinated competitive procurement to serve customers at the lowest overall delivered cost. NESCOE is now developing a "baseline" of indicative costs for two study years, 2016 and 2020, for representative scenarios. Consultants will provide ranges of indicative costs associated with various options for developing new on- and off-shore wind resources in New England and New York and representative transmission development scenarios that could facilitate the delivery of energy from new renewable generators in New England.

[146] However, California's new Renewable Auction Mechanism for eligible projects in the 1 MW to 20 MW range employs a standard contract, without negotiation of prices or terms.
[147] *See* http://www.nescoe.com/uploads/September_Blueprint_9.14.09_for_release.pdf.
[148] *See* http://www.nescoe.com/uploads/Governors_and_Premiers_2009_Resolution.pdf.
[149] *See* http://www.nescoe.com/uploads/Report_to_the_Governors_July_2010.pdf.
[150] NESCOE Status Report: Coordinated Renewable Procurement, Aug. 10, 2011, http://www.nescoe.com/Coordinated_Procurement.html.

4.9. Other Ways to Facilitate Development of WREZ Hubs

Utilities proposed the following ideas when asked what mechanisms beyond joint or coordinated procurement might facilitate development of WREZ resources and associated transmission:

- *Tradable renewable energy credits* – There was significant interest among utilities in legislative and regulatory changes that would allow greater reliance on tradable credits, in order to reduce the amount of transmission that needs to be built.[151]
- *Open season* - Several utilities suggested open season as a model for getting transmission built to WREZ hubs.[152]
- *Interstate highway model* – This concept refers to federal funding for transmission to bring energy from renewable-rich regions to other parts of the country, or socializing transmission costs among ratepayers that benefit from the project.[153]
- *Permitting in advance of need* -- One regulated utility said it will continue to work with the PUC to advance ideas for projects that might be needed eventually – for example, getting projects permitted that may not be built in the end.
- *Making transparent the available capacity on transmission networks* – Such an effort would provide clarity on where transmission build-outs would be most practical.
- *Regional transmission organization* – A couple of utilities mentioned this as a potential solution.
- *Merchant transmission* – Several utilities noted the potential role of merchant developers in building interstate transmission in the West, while pointing out the need for buyers at the end of the line.
- *Combining balancing authorities* – Some smaller utilities said they are having difficulty balancing wind resources on their own.
- *Cost recovery for transmission in advance of generation* – Provisions such as those in Colorado Senate Bill 100 could facilitate cost recovery for transmission built to renewable-rich areas.

Turning to responses from jurisdictions, open season was recommended by several government officials interviewed as a potential model to facilitate development of WREZ hubs. One jurisdiction suggested that a utility put out a call for renewable resources to fill a new 500 kV line from a particular zone. Another state pointed out that this model would not solve misalignment with permitting timelines and lack of assurance of the transmission on-line date. This state recommends a pilot program to conditionally permit transmission lines to facilitate open season processes, with coincident RFPs across utilities in the West to determine geographic areas of interest for resource development associated with these lines.

A few jurisdictions mentioned carbon requirements as a better mechanism for efficient procurement of renewable resources, instead of RPS policies or clean energy standards that specify requirements for certain types of resources.

The California Legislature recently granted the PUC authority to approve recovery of prudently incurred costs for transmission lines "necessary to facilitate achievement of the renewables portfolio standard" if

[151] *See* Sections 5.1 and 6.2.
[152] *See* Section 3.8.
[153] Most utilities and regulators expressed opposition to broadly allocating transmission costs to ratepayers based solely on broadly defined benefits, in part due to loss of control as well as perceived economic disincentives for cost-effective transmission alternatives such as demand-side measures and local generation.

FERC denies cost recovery and in the event the line is not completed.[154] Such backstop authority may be exercised for in-state or interstate lines.

Following are other mechanisms that regulators suggested were important for developing WREZ hubs:

- Consolidation of balancing authorities
- Robust trading of renewable energy credits
- Merchant development of transmission lines
- Federal backstop funding for interstate transmission lines
- Involving BPA and WAPA to spark regional development
- A region-wide Energy Imbalance Market
- Greater coordination of subregional planning groups
- Region-wide discussions – for example, on transmission expansion planning

Responding to a question about whether feed-in tariffs (FITs) [155] could stimulate development of transmission to WREZ hubs, enabling resource development in these areas, state officials interviewed generally saw FITs as too expensive to garner much support, particularly in a depressed economy. Utilities were nearly unanimously skeptical. The vast majority do not see FITs as a practical means for building demand for transmission lines. Utilities' concerns centered on higher costs for acquiring renewable resources in part from lack of competition, compared to RFPs, auction mechanisms[156] and utility development/ownership, as well as risk to the utility for transmission cost recovery over the life of the asset, unless ratepayers or the federal government serve as a financial backstop.

One utility characterized building transmission to support FITs as building transmission on speculation – not the utility's role. Another utility raised concern about meeting reliability and RPS goals if FIT contracts are simply a "put" to the utility, where the utility must take whatever energy is offered, but the project owner does not have to post a security deposit and is not subject to damage provisions.

There are a couple of exceptions to these points of view. BC Hydro operates under a province-wide standard-offer program, and the province is considering making renewable energy zone- or technology-specific standard offers. Another utility noted that a FIT with a high price supports development in a given area, though it is an expensive way to serve customers. According to the utility, the challenge is to simplify and streamline the FIT procurement process in a cost-effective way. Further, the state would need to deem used and useful the transmission lines designed to serve the areas targeted by the FIT to ensure that the utility could recover the cost.

It is important to note that utilities responded to this question based on the common FIT structures in place in the U.S. at the time of the interviews. However, similar to the open season model described below, FITs could be used to develop subscriptions for transmission service. Under such a model, a

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[154] *See* Public Utility Code 399.2.5 at http://www.leginfo.ca.gov/cgi-bin/displaycode?section=puc&group=00001-01000&file=399-399.9.

[155] FITs are a policy mechanism to encourage renewable resource development. They typically offer guaranteed access to the electric grid and payments to project owners for generation from qualified renewable energy systems under standard long-term contracts. Prices typically are set through administrative calculations that model generic production costs for particular technologies. Preset prices may be subject to adjustments based on market prices or other triggers. *For a primer on FITs, see* National Association of Regulatory Utility Commissioners, *Feed-in Tariffs: Frequently Asked Questions for State Utility Commissions*, June 2010, http://www.naruc.org/Publications/NARUC%20Feed%20in%20Tariff%20FAQ.pdf.

[156] Oregon uses competitive auctions for FITs for projects over 100 kW. California's new FIT uses an auction mechanism, as well.

transmission line would be built only if the signed FIT contracts reached a level sufficient to support the line, with financial penalties for contract default.

4.10. Policies and Regulations That Affect Coordinated Development

Most government officials interviewed said that no changes are needed in statutes or regulations to facilitate coordinated resource procurement. All that is required is an interest by utilities and a demonstration that coordinated resource procurement would lower costs.

A few jurisdictions said statutory or regulatory changes are needed to address challenges with siting interstate lines. One regulator said state legislation that would make it easier for merchant developers to build transmission would help.

Some states require utilities to submit long-term transmission plans on an identical schedule, distinct from resource plans. While these processes do not require utilities to act jointly, transmission planning with aligned schedules may reveal opportunities for cooperation. Other states require detailed transmission planning as a part of the IRP process. In either case, transmission plans to access renewable energy zones may be a required component.[157] In addition, some states promote transmission to renewable energy zones through attractive cost recovery provisions such as Construction Work in Progress.

4.11. Considering Long-Term Needs, the Public Interest and Regional Benefits

Ability to Focus on Long-Term Needs
Regulatory utility commissions in the West generally have authority to make decisions that aim for optimal solutions for long-term renewable resource needs, rather than simply focusing on keeping rates as low as possible in the near term. For example, one commissioner said the PUC has pressed its regulated utilities to develop solar resources, finding it to be in the best interest of ratepayers in the long run.

A regulator in a state with aggressive renewable energy targets pointed toward upward pressure on rates in the short-term while anticipating lower costs in the long run. In another state, a statutory cap on RPS-related costs may constrain the PUC's ability to consider long-term needs for renewable resources.

Optimal solutions may be viewed simply as building renewable resources in a timely fashion to accomplish the state's renewable energy objectives. In several states, a significant number of contracts selected in RFP processes are not coming to fruition. While some jurisdictions see benefits in coordinating procurement by multiple utilities, some states are simply focused on trying to meet high renewable energy targets, rather than optimizing development.

One jurisdiction noted the importance placed on long-term IRPs to inform utility decisions. Another said differing viewpoints on long-term needs and who benefits creates cost allocation issues for multi-state utilities.

[157] *See* Section 3.1.

Public Interest

Generally, “public interest” is not well-defined in state statutes on utility regulation. As a result, regulators may feel they have a fair amount of discretion to interpret public interest in each proceeding based on evidence in the record. On the other hand, such ambiguity leads some regulators to approach the issue conservatively – for example, not taking into account the health or carbon emissions impacts of utility resource decisions. In some jurisdictions, utility commissions may not consider environmental impacts except as they might be reflected in future retail rates, nor can they consider economic development. Siting statutes may provide more detailed guidance – for example, requiring that siting decisions consider the environmental impact of the project.

According to one regulator, the public interest includes only ratepayers and utilities. Another regulator pointed out that the PUC’s clients are ratepayers, bill impacts must be taken into account, and only costs recognized by the state legislature may be included in rates.

Some utility regulators face challenges in influencing transmission planning to achieve their public interest objectives. For example, in California, transmission planning falls to CAISO and CTPG.

Regional Benefits

Generally, while regulators may consider what’s best for the region as a whole, their decisions must be based on what is best for the individual state or province they serve. Thus, what’s best for the region takes a back seat to what’s best for local stakeholders – in particular, ratepayers must be the beneficiaries.

Some jurisdictions pointed out historical approvals of coal, nuclear and transmission facilities with benefits that extended well beyond an individual jurisdiction. So in some respects, approving projects that have broad regional benefits is nothing new. How states and provinces apply a regional perspective to renewable energy development remains to be seen, however.

How to define regional interests is itself a challenge. For example, states are trying to capture a diverse array of benefits through renewable energy standards – jobs and economic development, portfolio diversity, reduced impact from fuel price volatility, lower long-term rates and reduction of greenhouse gas emissions. Some of these values may be in conflict – for example, lower rates vs. economic development.

In some jurisdictions, what’s best for the region may be a consideration in applications for transmission siting and cost recovery, particularly in jurisdictions with a goal to become net energy exporters.

One regulator pointed out that in adjudicated cases the PUC is constrained by statute, but in front of the Legislature or at regional discussions the PUC can advocate a more regional approach to public interest.

The Wyoming Legislature passed House Bill 111 in 2010 to move the ball forward on regional approaches to transmission. The bill explicitly allows the Wyoming Public Service Commission to meet with other PUCs in the region to develop a common set of facts for transmission regulation in a docketed proceeding, conduct joint hearings on transmission, and consider the regional effects of its decisions on the utilities it regulates.[158]

4.12. Potential Partners for WREZ Resources and Associated Transmission

Utilities were asked to identify potential partners for coordinating procurement of renewable resources and associated transmission considering the utility-specific WREZ model results the utilities received. Table 11 shows the results.

Utilities give a variety of reasons why they would tend to partner with a particular utility on procurement of renewable resources, transmission development or both. The most common reason is proximity – to the other utility's service area, to the targeted resource area, and to available transmission from that area. Utilities also cited similar ownership structure and management philosophy as important for successful partnerships. Another factor in cooperative efforts is mutual membership in an association or a subregional planning group, or where there is a long history of cooperation between the utilities.

Many utilities cited utility size as a factor for partnering on resource procurement. Large utilities generally are not interested because they have sufficient demand to achieve economies of scale. Small utilities tend to have more interest in partnering on resource procurement in order to achieve those economies. Most utilities, large and small, expressed interest in transmission partnerships.

Utilities cited several barriers that fall into two categories: 1) factors internal to the utility and 2) external factors.

Internal factors are those that are constitutive of the organization or which arise from within the utility itself, such as the utility's size, its business philosophy, and whether the utility sees its peers as competitors rather than partners. Similarly, the utility's ownership structure may serve as an impediment to partnerships. Consumer-owned utilities expressed reluctance to partner with investor-owned utilities and *vice versa*. A few utilities cited potential difficulty in aligning cost/benefit methods for determining whether a project makes sense for multiple utilities.

The most referenced external factor undermining a utility's ability or willingness to seek out partners is the diversity of regulatory requirements across states and provinces and the differing obligations these regulations impose on utilities. Included in this category are divergent resource planning, acquisition and cost recovery processes, as well as state or provincial preferences for local resources. Several utilities mentioned the difficulty in gaining "critical mass" or enough momentum to get a project moving with multiple partners. Another important external influence is proximity to local renewable resources. Many utilities said there is no need to seek out partners because local resources can satisfy the utility's needs.

According to one Mountain region utility, utilities are more likely to have to go it alone where loads are small and distance between markets is large.

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[158] *See* section 37-2-114 at http://legisweb.state.wy.us/statutes/statutes.aspx?file=titles/Title37/Title37.htm. The "region" includes any state with a border contiguous to Wyoming and the states of Arizona, California, Nevada, New Mexico, North Dakota, Oregon and Washington.

Table 11. Potential Partners Identified by Utilities for WREZ Resources and Associated Transmission
(Asterisk indicates no specific response)

Utility	Potential Partners Identified by Utility Based on WREZ Modeling	Other Potential Partners Identified by Utility
Arizona Public Service	Not looking for partners to procure renewable resources	*
Avista	Willing to partner but no utility identified	*
BC Hydro	Not looking for partners to procure renewable resources but working with PG&E and Avista on potential construction of a transmission line from Canada to northern California	*
Colorado Springs	Tri-State and PSCo	Black Hills Energy
El Paso Electric	Public Service of New Mexico	*
Eugene Water & Electric Board	Any utility identified by WREZ modeling as potentially interested in similar resource areas (PG&E, SMUD, PacifiCorp, PGE, Avista, PSE, Seattle, Tacoma, BC Hydro)[159]	Bonneville Power Administration and other public entities
Idaho Power	PacifiCorp[160]	*
Imperial Irrigation District	*	Southern California Public Power Authority members[161]
Los Angeles Department of Water & Power[162]	*	Southern California Public Power Authority members
NV Energy	California utilities[163]	*
Northwestern Energy	Not looking for partners to procure renewable resources	Montana Dakota Utility
PacifiCorp	Partnering with PGE and Idaho Power on transmission; other utilities also are potential transmission partners	Bonneville Power Administration (for transmission)
Pacific Gas & Electric	SCE, SDG&E, SMUD, APS; for transmission, PacifiCorp, Avista and BC Hydro	Other municipal utilities
Portland General Electric	PacifiCorp, Idaho Power and Bonneville Power Administration for transmission	*
Public Service of Colorado	Colorado Springs and Tri-State	*
Public Service of New Mexico	Willing to partner but no utility identified	*
Puget Sound Energy	Willing to partner but no utility or zones identified	*
Sacramento Municipal Utility District	Imperial Irrigation District, LADWP, PG&E, SCE and SDG&E	California ISO, S. California Public Power Authority, Transmission Agency of N. California, Turlock Irrigation District and Western Area Power Administration
Salt River Project	Willing to partner but no utility identified; worked with southern California entities in the past	*
San Diego Gas & Electric	SCE and PG&E[164]	*

[159] EWEB has partnered in the past with Portland General Electric, PG&E, PacifiCorp, Avista, and municipal utilities and irrigation districts in California.
[160] Idaho Power is partnering with PacifiCorp on the Gateway West transmission project.
[161] Members include Imperial Irrigation District, LADWP, and the cities of Anaheim, Azusa, Banning, Burbank, Cerritos, Colton, Glendale, Pasadena, Riverside and Vernon. *See* http://www.scppa.org/pages/members/membersList.html.
[162] Participating in IID's open season process for the Path 42 upgrade to enable delivery of geothermal resources to LADWP. *See* Mohammed Beshir, LADWP, presentation to California Energy Commission, May 17, 2011, http://www.energy.ca.gov/2011_energypolicy/documents/2011-05-17_workshop/presentations/08_Beshir_LADWP.pdf.
[163] While expressing an openness to partner with California utilities, NV Energy finds it unlikely that projects, particularly transmission projects, would acquire a critical mass of partners to move forward.

Utility	Potential Partners Identified by Utility Based on WREZ Modeling	Other Potential Partners Identified by Utility
Seattle City Light	Tacoma Power[165] and Puget Sound Energy	Snohomish County PUD
Southern California Edison	Not looking for partners	*
Tacoma Power	Willing to partner but no utility identified	*
Tri-State	Not looking for partners to procure renewable resources	*
Tucson Electric Power	Has explored partnering with SRP and APS	*

[164] The PUC requires that the three California investor-owned utilities coordinate resource procurement by simultaneously filing RFPs. SDG&E considers this a form of partnering.
[165] Seattle City Light jointly developed an irrigation-canal hydroelectric project with Tacoma Power.

Chapter 5. Market Mechanisms to Support Renewable Resources

This chapter presents views from PUCs and provincial energy ministries on regional market mechanisms to support development of higher levels of renewable resources in the West: 1) a West-wide market for trading unbundled renewable energy credits; 2) ***c****oordination across balancing authorities to facilitate intra-hour trading; and 3) other market tools.*

5.1. West-Wide Market for Trading Unbundled Renewable Energy Credits

To facilitate compliance with state renewable energy standards, jurisdictions often allow renewable energy credits procured separately ("unbundled") from the associated electricity to satisfy a portion of the renewable resource obligation. In addition to limiting the percentage of unbundled credits that may be used to meet RPS requirements, states may restrict the location of the associated generating facilities. Other state-specific requirements for renewable energy credits also hinder trading, such as eligible fuels and technologies, the date the generating unit began operation, and how credits are defined, including any conveyed environmental attributes.

Nearly all government officials interviewed for this report expressed support for increased trading of unbundled renewable energy credits, while noting limits on this practice today and the difficulty in changing such restrictions. Interviewees pointed out that credit trading reduces the cost of RPS compliance because the associated electricity does not need to be delivered to the credit purchaser, reducing the need for new transmission facilities.[166] However, jurisdictions have not performed analysis to quantify the potential benefits for their consumers.

Even jurisdictions without RPS requirements have an interest in unbundled credits, because project owners in these locales can sell credits to LSEs elsewhere.

States may allow the utility to retain a portion of revenue from sales of unbundled credits; others require the utility to apply all of the revenue to offset ratepayer costs. One regulator noted that the ability to earn revenue on sales of unbundled credits would encourage the utility to acquire renewable energy projects beyond mandated RPS levels.[167]

Some regulators expressed reservations about increased trading of unbundled renewable energy credits. Two raised concern that their native resources may lose out to cheaper resources elsewhere. Another concern is that investments in transmission for export could be stranded. One regulator suggested that mechanisms to mitigate disparities between winning and losing jurisdictions would be important to earn support for any market mechanism to increase credit trading throughout the West.

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[166] A study for the Western Electric Industry Leaders Group on the transmission needed to meet RPS and carbon requirements under various scenarios estimated the total annual value of renewable energy credit trading in 2020 at $351 million – the difference in procurement cost between acquiring local resources vs. WECC-wide resources through credit trading. *See* Ren Orans and Arne Olson, Energy and Environmental Economics, Inc., "Load-Resource Balance in the Western Interconnection: Towards 2020," 2008, http://weilgroup.org/E3_WEIL_Complete_Study_2008_082508.pdf. *Also see* the renewable energy credit trading scenario modeled by Lawrence Berkeley National Laboratory as part of its analysis on least-cost selection of WREZ resources in the West, described in Chapter 1 of this report.

[167] The utility cannot claim any renewable energy attributes for the portion of facility output where the utility sold the associated renewable energy credits.

Whether unbundled credits from out-of-state resources would get credit for reductions in greenhouse gas emissions is another issue jurisdictions will need to address.[168]

In one state's view, unbundled credits are inconsistent with the way it addresses financing of renewable energy projects – through long-term contracts.[169] Instead, the state views unbundled credits as a compliance product to backfill a shortage in its renewable energy portfolio and as a way to impose price discipline in renewable energy solicitations.

Transparency, consistency, tracking and verification were common themes echoed by the government officials interviewed as elements that support credit trading.

One jurisdiction recommended a centralized trading platform for renewable energy credits in the West.[170] In this context, one regulator pointed toward the need for a market monitor. Conversely, another jurisdiction believes that bilateral trades will persist in the West for the foreseeable future – for energy, capacity and unbundled renewable energy credits.

Some regulators expressed support for integrating variable energy resources closer to the source to address concerns about "dump energy,"[171] which unbundled credit trading may exacerbate. Others noted limits to this approach in remote locations with low loads.

Another recommendation put forward is reciprocity arrangements. Under this approach, two states would agree to accept renewable energy credits from facilities located in either state and qualifying for the host state's RPS – at par or at a pre-determined discount and potentially in limited amounts. Short of that, states could agree to expand geographic eligibility or relax energy delivery requirements under specified conditions indicating tight supplies of renewable resources.[172]

Alternatively, one regulator suggested harmonizing RPS requirements to allow out-of-state resources to qualify for *bundled* renewable energy credits. In that case, the eligible electricity would be delivered along with the associated environmental and other attributes of the renewable resource. That would reduce emphasis on trading unbundled credits and avoid an increase in dump energy.

5.2. Coordination Across Balancing Authorities to Facilitate Intra-Hour Trading

Jurisdictions generally support further steps toward intra-hour trading in the West to enable development of renewable resources and reduce costs for consumers. The AESO in Alberta and the CAISO in California already coordinate across balancing authorities within their footprint. In addition,

[168] For a discussion of these issues, *see* Lori Bird, Caroline Chapman, Jeff Logan, Jenny Sumner and Walter Short, *Evaluating Renewable Portfolio Standards and Carbon Cap Scenarios in the U.S. Electric Sector*, National Renewable Energy Laboratory, May 2010, pp. 18-25, http://apps3.eere.energy.gov/greenpower/pdfs/48258.pdf.

[169] However, this jurisdiction acknowledged that some restructured states address long-term financing needs by requiring LSEs to enter into long-term contracts for unbundled renewable energy credits.

[170] The Western Renewable Energy Generation Information System, housed in the Western Electricity Coordinating Council, is an interconnection-wide tracking system for renewable energy credits. However, it is not a trading platform.

[171] Dump energy represents an amount of economic energy that, due to transmission constraints, cannot be used and must instead be replaced by more expensive resources that can be delivered to the needed area.

[172] For a detailed review of potential approaches, *see* Edward A. Holt, *Increasing Coordination and Uniformity Among State Renewable Portfolio Standards,* prepared for Clean Energy States Alliance and the Northeast/Mid-Atlantic RPS Collaborative, December 2008, http://www.cleanenergystates.org/Publications/CESA_Holt-RPS_Policy_Report_Dec2008.pdf.

Alberta and British Columbia are discussing the potential for dynamic scheduling across their jurisdictions.

Western utilities and other stakeholders are exploring a proposed, voluntary Energy Imbalance Market – a real-time centralized dispatch service that would allow participants to use the lowest cost generation in the market to balance loads and generation across balancing authorities and reduce the total amount of load-following reserves needed.[173]

However, while assuming such a market will reduce costs across the region as a whole,[174] PUCs want to know the specific costs and benefits for the utilities serving *their* customers, believing there will be some shifting of costs and benefits among jurisdictions. One regulator pointed to cost overruns by RTOs establishing their energy markets elsewhere in the U.S., even though there is no active effort in the West to establish new day-ahead energy markets. Regulators also said they want to understand who would operate any Energy Imbalance Market and the potential implications for their state.

While most jurisdictions haven't reached the point where they have delved into the details of potential structure for an Energy Imbalance Market, one commissioner recommended the following features: 1) a regulatory role for state governments; 2) an independent market monitor; and 3) education for stakeholders. Another commissioner recommended that market prices be posted for the public and successful bidders receive their bid prices as payment, rather than market clearing prices.

One commissioner stressed that any market innovations the West develops for improved integration of wind resources should not force the region into a particular market structure for other purposes. To the extent the region wishes to move toward additional regional cooperation across balancing authorities, market structure issues should be addressed upfront.

FERC's Notice of Public Rulemaking on Integration of Variable Energy Resources proposed a requirement to provide transmission customers with the option of scheduling in 15-minute intervals.[175] One regulator suggested an analysis of 15-minute vs. 30-minute markets, alluding to the differing positions of FERC vs. some Western utilities and BPA.

5.3. Additional Market Tools to Facilitate Development of Renewable Resources

According to some government officials interviewed, putting a price on carbon would be the most effective tool for developing renewable resources. One jurisdiction suggested that states move from renewable resource requirements to a low-carbon standard for a more liquid market and better transferability of resources across the West.

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[173] *See* http://www.westgov.org/EIMcr/index.htm for documents describing a West-wide Energy Imbalance Market.
[174] *See* http://www.wecc.biz/committees/EDT/Documents/Forms/AllItems.aspx for documents describing the results of WECC's analysis of a West-wide Energy Imbalance Market. For a roadmap that explains how individual utilities and other market participants can use this data to estimate participant-specific benefits, *see* http://www.wecc.biz/committees/EDT/EDT%20Results/Participant%20Benefits%20Calculation/E3_EIM_Benefits_Study-Roadmap_for_Participant_Benefit_Estimation_2011-07-14.pdf.
[175] *See* 133 FERC ¶ 61,149, Docket No. RM10-11-000, Nov. 10, 2010, http://www.ferc.gov/whats-new/comm-meet/2010/111810/E-1.pdf.

Some jurisdictions said development of regional solutions will require commitment by elected officials to overcome the current patchwork of state requirements, as well as the difficulty in getting consensus on an interconnection-wide transmission plan and producing any tangible effect.

Several jurisdictions pointed toward the need for real-time markets to value energy at the appropriate time interval, as well as the importance of dynamic scheduling. One commissioner said balancing authority consolidation is important for integrating variable energy resources at reasonable cost, pointing toward recent analysis prepared for the National Renewable Energy Laboratory.[176] Other regulators noted the importance of developing additional ancillary services to better integrate these resources. Better forecasting requirements for wind and solar also were recommended.

Another commissioner said any mechanisms that increase the certainty and firm delivery of out-of-state renewable resources would help. That includes addressing the concern that transmission lines approved for the purpose of delivering renewable resources might be used to deliver power from coal plants.

Noting legislative initiatives that have made it more difficult to develop renewable resources in the state, one commissioner said the electorate needs to be educated on the issues so they demand energy from renewable resources.

[176] *See Western Wind and Solar Integration Study*, prepared by GE for NREL, May 2010, http://www.nrel.gov/wind/systemsintegration/wwsis.html.

Chapter 6. Next Steps and Regional Issues of Interest

This chapter presents views from utilities, PUCs and provincial energy ministries on next steps for the WREZ initiative and issues of interest for regional discussions.

6.1. Next Steps: Discussion Groups on WREZ Hubs of Common Interest

Under its grant proposal to U.S. Department of Energy for the WREZ initiative, WGA proposed to convene small groups of utilities and utility regulators to discuss possible coordination of resource procurement from zones of common interest, unless interviews conducted for this report indicated a different strategy. Following is a summary of utility and state/provincial responses to questions directed at this proposal.

Potential Value of Small Discussion Groups
Utility views. Most utilities support the idea of convening small groups of utilities and regulators to discuss development of WREZ hubs. Utilities had different views on the form and function of such dialogue and whether it could be successful in driving coordination of resource procurement from zones of common interest. Some utilities expressed concern over the number of planning groups and meetings currently in place and potential duplication of efforts.

Many utilities noted that it is useful to bring the right people to the table – utilities, generation project developers, merchant transmission developers and other stakeholders. Ideally, dialogue may lead to agreement on a common goal and ultimately to achieving that goal. Even where parties remain in conflict about what they think needs to be done, hearing various points of view helps parties ask the right questions, according to the utilities. Dialogue can help identify whether there are opportunities to work together or whether it is necessary to proceed alone.

One utility suggested that discussion groups target utility associations to speak for the utilities they represent. Another said the conveners need to make clear what the process is trying to achieve and whether there is value in joining the discussion.

While tentatively supportive of the proposal for small group discussions, one utility pointed out two initial challenges. First, all participants must agree there is a common problem that calls for a common solution. Second, they must agree on the analysis that will be used in the discussion, including assumptions and baselines. The utility believes that reaching agreement on these points will be difficult.

Among utilities that see limited or no value in convening group discussions on developing WREZ hubs, one utility said the effort may lead to the creation of a new bureaucracy to address issues that could have been resolved through direct collaboration among utilities. Another utility said lack of communication between utilities and commissions is not impeding development of transmission. According to a third utility, resources would be better spent on supporting the work of existing subregional planning groups.

One utility explained that the usefulness of convening discussions on resource procurement turns on whether there is an economic reason to do so. Moreover, the utility and its commission do not focus on the high renewable resource targets envisioned in the modeling for the WREZ project, and therefore do not see the need to discuss coordinated procurement.

Utilities said they must prioritize participation in various groups and meetings in the West. One utility said it would more likely attend meetings that have a material impact on, for example, the cost of transmission, than discussions on how to develop distant renewable resources. Another utility suggested that rather than launching a new process, WGA could convene discussions on a regulatory environment that enables the development of specific resources or resource areas.

State/provincial views. Most jurisdictions believe convening small discussion groups with utilities and regulators on possible development of specific WREZ hubs is a good idea. One jurisdiction pointed out that development of the Columbia River dams arose from a similar effort.

A few jurisdictions, however, do not believe these discussions would be productive, though they do not oppose such efforts. One of these jurisdictions suggested a broader look at coordinating development of resources and transmission overall, without a focus on renewable resources.

Jurisdictions suggested that benefits for all states and provinces be articulated up-front in order for these discussions to be productive. Some believe they will be net losers if remote WREZ hubs are developed for a variety of reasons:

- Freeing up lower-cost renewable resources elsewhere may make in-state development less attractive.
- Differing resource makeup (hydro- vs. thermal-based systems) or market structure (restructured vs. non-restructured) may put them at a disadvantage.
- Tied-up transmission rights hamper competition.
- Continuing subsidies and RPS provisions encourage in-state resource development and disadvantage development elsewhere.

Conversely, some jurisdictions believe greater cooperation across states and provinces could keep rates lower for retail customers – also important for local economies.

One jurisdiction pointed toward NTTG, a subregional planning group with a Steering Committee that includes state PUC representatives and utility executives, as a good model for multi-state discussions.

Moving From a Conceptual Plan to Implementation

Utility views. A number of utilities emphasized the need to keep the groups small to make the meetings productive and streamline the process with other initiatives – for example, scheduling discussions to coincide with subregional planning group meetings.

Some utilities suggested specific ways in which planning could turn into action. One utility suggested convening a group of transmission planners to identify mutually beneficial transmission projects to the WREZ hub of interest. Another recommended that discussion groups focus on transmission projects that address areas of interest identified through WECC's transmission planning studies. A third utility said it is important to validate with utility resource planners and procurement staff that the group is on the right path concerning where resources may actually be developed. The group can then work toward agreement on transmission projects that make sense and establish a process for permitting – who does it, how to pay for it and who holds the permit.[177]

[177] One utility put the cost of permitting at less than 5 percent to 10 percent of the total project cost.

Utilities also emphasized the need to build political support to carry forward ideas. One utility said that while successful projects ultimately are developed from the bottom up, significant political weight may be needed for regional transmission lines. Another suggested developing a consensus proposal for regulatory or legislative changes. For example, it might be useful to build support for cost recovery mechanisms that reduce regulatory lag.

Discussion groups could make utilities more aware of each other's IRP action plans, according to one interviewee. It also might be helpful to review variations in legislative or regulatory requirements among jurisdictions for competitive bidding processes and lack of direction regarding joint or coordinated utility procurement in rules. A few utilities went further, saying competitive bidding requirements may be a barrier to coordinated development of WREZ hubs.

Utilities also pointed toward jurisdictional differences regarding pre-construction approval (if any), acknowledgment or approval of resources and transmission in resource planning processes, and differences in cost recovery mechanisms.

Utilities pointed out that regulators may find it difficult to discuss resource plans with utilities. Commissions are involved in a number of regulatory proceedings at any one time and therefore face *ex parte* concerns or the appearance of improper communication. Commissions have a heightened sensitivity to appear not to pre-judge any matter, a challenge for productive meetings. One suggestion in this regard was to focus the goals of a discussion group on specific outcomes, such as developing geothermal resources located on federal land.

A couple of utilities expressed skepticism that discussion groups can lead to action on WREZ and transmission development. According to one utility that has been disappointed by some of the coordinated transmission planning efforts in its region, the processes have primarily served to advance each utility's own interests.

<u>State/provincial views</u>. Jurisdictions agreed that utility commissions must be involved to press their utilities to engage in collaborative discussions. Going further, one commission noted that it is a driving force in utility planning and procurement processes, and that most of these activities are focused on long-term solutions. Another stressed the importance of requiring utilities to report back to the commission with proposed projects stemming from WREZ discussions.

In terms of which utilities should be involved, one jurisdiction said discussions should include the incumbent utility in the renewable development zone and the utilities and regulators in between that zone and the intended delivery points. Another said it is important to have utility executives and commissioners directly involved in the discussions – people with a say in decision-making – as well as knowledgeable staff.

Consistent with the utility interviews, several regulators suggested that groups start out small. Some suggested that discussions begin with utilities alone. Next, utility commissions should be included, followed by economic development institutions. As discussions progress, governors' and premiers' offices should get involved. One commissioner said limiting discussions to two states may be more productive at least early in the process, with the potential for other jurisdictions to join.

Another commissioner recommended the discussion groups first include only the high-load states to see if they have an appetite for importing resources, noting that other jurisdictions do not have the buying power to drive the process. Others noted the importance of identifying early-on where the power from the WREZ hub would be going and a focus on WREZ hubs of common interest to multiple utilities.

Acknowledging that other stakeholders may raise concerns about being left out of these discussions, one regulator suggested that stakeholders be advised that the meetings are occurring and that stakeholders will receive reports on the meetings and be brought into the process as it progresses. Some regulators pointed out that detailed information on proposed locations of renewable energy and associated transmission facilities will need to be vetted with environmental stakeholders.

Working on concrete projects is viewed as an important feature of these discussion groups. Beyond the practicality of such an approach, concrete projects will have analysis available that could trigger valuable discussions.

On the other hand, one regulator said that no firm commitment is needed to discuss a project, its barriers and ways to overcome them. Utilities could then bring forward to the PUC the barriers and potential solutions discussed in the group.

One regulator suggested as a goal an MOU that sets out mutually agreeable parameters of an agreement for a transmission project across several jurisdictions, with the primary justification for the line to acquire renewable resources in a high-quality zone. Some regulators recommended that WREZ discussion groups consider information from individual state/provincial renewable energy zone initiatives, including any proposed routing of transmission lines.

One caution offered during the interviews is that regional planning should consider what will be politically acceptable to state legislatures that establish RPS requirements, including limits on out-of-state resources. Regionally optimal approaches will work only if proponents can demonstrate they will result in jobs and economic development in the jurisdictions involved.

Issues Regarding Information-Sharing

Utility views. According to many utilities, the information utilities share to facilitate cooperation does not need to include the type of information that would be subject to confidentiality or competitiveness concerns. While there may be limits on information exchange, sufficient useful information can be shared to further dialogue once a common interest has been identified. One utility noted that the only major areas of confidentiality are proprietary resource data and certain procurement planning activities, and neither of these areas is important for these discussions. According to the utility, as long as the right people weigh in to ensure the group is looking at the right place for resources, there should be no issue.

Similarly, another utility explained that it did not foresee a lot of sensitive information required for a productive dialogue. Most often the discussion is not about price, but about feasibility and quality of sites. While generally agreeing that there are few confidentiality issues, identifying potential generators during the planning stages of a transmission project may be a sensitive area. Where confidential information is needed, several utilities noted that non-disclosure agreements can allow for further dialogue.

One utility suggested that confidentiality is less of an issue with utilities than it is with merchant developers, who want to protect their information from other developers.

Facilitating Agreements in Principle
A number of factors affect the ability to come to agreements in principle between utilities, between jurisdictions and across both these groups. According to utilities, needs must be aligned, common goals must be identified, and barriers to realizing these goals must be addressed. One utility believes that agreement among utility executives is key. Some utilities noted that it would be helpful to have political support underpinning the goals being advanced.

According to government officials, discussion groups would need to address the concern that regulators will be making decisions on some of the projects discussed. That may create at least the perception that they would be pre-judging a case that may be brought to them for a formal decision. The degree to which that is a concern depends on the firmness and specificity of any agreement undertaken by the group, according to one regulator. At the same time, another regulator said disclaimers in any agreement would create uncertainty and weaken the effectiveness of the process.

Northern Tier Transmission Group Steering Committee
The NTTG Steering Committee's charter may serve as a model to address these concerns: "Subject to the provisions of this Charter, the Steering Committee acknowledges that Steering Committee recommendations shall not be interpreted to prejudge any issue or otherwise be decisions binding on any state commission, and, as applicable, shall explicitly state that each state commission retains its decision-making authority; provided, that any state regulatory utility commissioner or any state commission's designated representative (or alternate) that is a member of the Steering Committee shall make reasonable efforts to support in good faith and to the extent possible the principles and objectives of Northern Tier and the Steering Committee." [178]

One regulator advised WGA to seek legal counsel early in the process from attorneys experienced in interstate compacts, in order to understand how far states may wish to go as a result of WREZ discussion groups or other joint state efforts. To the extent states wish to form a binding compact, Congressional approval is needed. The Federal Power Act has specific provisions for multi-state compacts to address siting of transmission lines across states.[179]

An analysis of NTTG's structure by a legal expert in this field concludes that NTTG successfully avoided creating an interstate compact that requires Congressional approval:[180]

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[178] *See* http://nttg.biz/site/index.php?option=com_docman&task=doc_download&gid=1085&Itemid=31.
[179] For transmission siting compacts, see Section 216(i) of the Federal Power Act:
(i) Interstate Compacts-
(1) The consent of Congress is given for three or more contiguous States to enter into an interstate compact, subject to approval by Congress, establishing regional transmission siting agencies to--
(A) facilitate siting of future electric energy transmission facilities within those States; and
(B) carry out the electric energy transmission siting responsibilities of those States.
(2) The Secretary may provide technical assistance to regional transmission siting agencies established under this subsection.
(3) The regional transmission siting agencies shall have the authority to review, certify, and permit siting of transmission facilities, including facilities in national interest electric transmission corridors (other than facilities on property owned by the United States).
(4) The Commission shall have no authority to issue a permit for the construction or modification of an electric transmission facility within a State that is a party to a compact, unless the members of the compact are in disagreement and the Secretary makes, after notice and an opportunity for a hearing, the finding described in subsection (b)(1)(C).
[180] *See* Robin Kundis Craig, "Constitutional Contours for the Design and Implementation of Multistate Renewable Energy Programs and Projects," *University of Colorado Law Review*, Vol. 81, No. 3, Summer 2010, http://papers.ssrn.com/sol3/papers.cfm?abstract_id=1482611.

> The NTTG Steering Committee consists of the state regulatory utility commissioners, utility representatives, and representatives of consumers groups. Thus, states do participate, although they do not control the proceedings. Moreover, while the Steering Committee does approve project charters, projects in the Northern Tier Initiatives, and expansion plans, its goal is again planning and coordination. Most importantly, none of its actions replace, supersede, or even influence individual state or federal regulatory requirements, and the state commissioners remain explicitly free to take neutral or even contrary positions in their state regulatory processes. Thus, the contract-like commitments that characterize interstate compacts are absent.

While some states may wish to avoid formal interstate compacts, there are several advantages. Among them, providing investors and utilities with the confidence to participate in multi-state projects and programs, protection against existing and future federal preemption, and avoiding dormant Commerce Clause challenges that could arise with regional incentives and preferences made available through multistate renewable energy efforts.[181]

FERC Order No. 1000 on transmission planning and cost allocation notes that "…agreements among states with respect to cost allocation may be particularly important for transmission facilities designed to meet transmission needs driven by Public Policy Requirements. States could pursue such agreements in various forms, including a committee of state regulators or through a compact among states that receives appropriate approval from Congress."[182] One utility regulator said such agreements could provide parameters under which parties could conduct negotiations and attract financing for projects.

6.2. Issues of Interest for Regional Discussions

Reactions to Five Specified Topics

Utilities, PUCs and provincial energy ministries were asked to comment on their interest in discussing at a subregional or regional level five specified topics:

1. Regional energy efficiency initiatives – for example, transforming regional markets for energy-efficient products such as consumer electronics
2. Standardizing renewable energy credits that are tradable across the West
3. Distributed generation, including the potential impact of solar PV on planning for resources, distribution systems and transmission
4. Future costs of renewable energy generation
5. Potential effects of carbon limits on resource and transmission development

Only item 2, standardizing renewable energy credits, garnered widespread utility interest. That topic also garnered strong interest from state and provincial representatives interviewed.

One utility said harmonizing renewable energy credits across the West is "the number one thing WGA could do for us." Another utility said it would be especially interested in discussions on this topic if they

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[181] ***Id.***

[182] FERC Order No. 1000 (Docket No. RM10-23-000) at 486-487, issued July 21, 2011.

included establishing a regional market for trading credits across the West, which the utility said would reduce costs for customers. Some utilities are interested in this topic in order to sell excess credits.[183]

According to one utility, improved trading of credits is necessary to optimize resource development, for efficient markets, and for a more efficient transmission system by allowing utilities to sink renewable energy at the closest possible point. Another said more flexible policies on trading renewable energy credits could help reduce price risk for utilities. Investor-owned utilities said WAPA, BPA and consumer-owned utilities must be brought into the discussion.

Other subjects raised in relation to trading renewable energy credits included ways to reduce transaction costs, integration and balancing issues when credits are sold separately from the underlying energy, and integration during periods of high wind/high water/low load.

Reciprocity was mentioned as an alternative to harmonization, whereby two states agree to accept renewable energy credits from facilities located in either state and qualifying for the host state's RPS – at par or at a pre-determined discount and potentially in limited amounts.

Regional energy efficiency initiatives did not elicit interest as a discussion topic from Northwest utilities, which already support extensive regional "market transformation" initiatives for energy efficiency[184] through the Northwest Energy Efficiency Alliance.[185] However, this topic received strong support among some utilities outside the Northwest, as well as PUCs and provincial energy ministries. Specific subjects suggested for discussion included best practices and collaborating on building and equipment standards. Broad regional support for market transformation activities would reduce energy efficiency costs throughout the West, as well the cost of meeting energy needs in the West.[186]

Most utilities and regulators viewed distributed generation as a local issue and irrelevant for regional discussion. Those interested in discussing this topic at a regional or subregional level suggested the following subjects:

- Wholesale distributed generation
- Resource planning issues
- Utility best practices
- Lessons learned on operational issues
- Research findings
- Advances in solar technology that reduce output variability
- Impacts on transmission systems
- Projects that utilities can collaborate on
- Determining how much solar a utility system can handle
- Reliability impacts of high solar penetration

[183] Commissions may require that revenue from utility sales of excess renewable energy credits be used entirely for ratepayers' benefit or provide a revenue-sharing mechanism.
[184] Market transformation initiatives aim to change the way people make energy-related decisions or make efficient products and services widely available.
[185] *See* http://neea.org/.
[186] CREPC and SPSC are discussing greater regional collaboration on energy efficiency. *See* http://www.westgov.org/wieb/meetings/crepcsprg2011/04-11agen.htm and http://www.westgov.org/wieb/meetings/crepcfall2011/10-11agen.htm.

The future cost of renewable resources is a topic most interviewees do not believe lends itself to discussion, with some saying it's not a problem the region can work together on to solve. Some interviewees noted that discussions on renewable resource costs already are taking place through utility IRP processes and WECC transmission planning. Among the utilities and jurisdictions interested in discussing this topic, specific subjects include:

- The cost and expected development of renewable resources absent subsidies
- Rate impacts of renewable resources and communicating the cost to legislators and stakeholders
- Price trends, including potential reductions in solar technology costs
- Manufacturer presentations on technological advances
- Supply and demand
- Integration costs
- The tradeoff between declining technology costs and quality of remaining resource sites

On the topic of carbon regulation, most interviewees said this issue is getting enough attention considering the lack of requirements in most jurisdictions. However, some interviewees expressed interest in discussing the effect on generation and transmission of forthcoming EPA regulations on criteria air pollutants, including potential retirement of coal plants, in tandem with potential future carbon regulation. A few interviewees suggested WGA convene discussions on shifting regulation of resource mix from state-centric renewable energy credits to carbon. One respondent is interested in discussing carbon emissions in the context of permitting projects.

Other Topics of Interest
Following are categorized responses to an open-ended question asking utilities, PUCs and energy ministries what other topics they would like to discuss at a subregional or regional level:

<u>Resource planning/procurement</u>
- Implications of supply surplus (especially wind) for retail customers
- Coordinated procurement

<u>Regulation</u>
- RPS vs. carbon targets, including a review of regulations in the West to see if they are aligned or working at cross-purposes
- Regional RPS or regional push for a national renewable energy standard
- West-wide carbon regulation
- Greater standardization across regions (generally)
- Addressing cost recovery risk for utility renewable energy projects
- FERC relicensing processes for hydro
- Decoupling and lost revenue adjustments to eliminate disincentives to demand resources

<u>Technologies</u>
- Electric vehicles
- Breakthrough technologies

<u>Incentives</u>
- Utility perspective on renewable resource incentives

- Impacts of renewable resource incentive structures on utilities
- Impact of renewable resource incentives on market efficiency

Variable energy resources

- Integration generally
- Integrating at source vs. sink
- Integration costs and cost allocation
- Regional mechanisms to mitigate integration issues and reduce costs
- Regulating reserves needed with increasing penetration of renewable resources
- Impacts from neighboring utilities as renewable resource levels increase
- Impact of solar (central station and distributed) on utility systems at high penetration
- Capacity value of wind and solar

Transmission

- Transmission investment decisions
- Building transmission from WREZ hubs
- Permitting for transmission
- Cost allocation
- Expanding transmission from Northwest states to California
- Balancing authority consolidation
- Intra-hour scheduling
- Contract path vs. flow gate analysis for congestion
- Improving relationships between organized and unorganized energy markets in the West
- Transmission pricing mechanisms to facilitate firming of wind closer to the source
- Addressing loop flow in a more integrated transmission market
- Open season processes

Appendix A. WREZ Interview Questions

<u>Questions for PUCs and Provincial Energy Ministries</u>

RENEWABLE RESOURCE PLANNING AND PROCUREMENT

1. How does any *state/provincial* renewable energy zones process affect resource and transmission planning and development for the utilities you regulate?

2. Regarding possible subregional planning for renewable resources:
   a. Is there value in coordination of renewable generation planning among utilities on a subregional basis?
   b. What, if any, advantages do you see in utilities coordinating with one another to develop high-quality renewable resources in a common area?
   c. Can subregional transmission planning as it exists today help facilitate potential partnerships for renewable energy development and associated transmission and, if so, how?
   d. How could subregional transmission planning groups specifically address development in Western Renewable Energy Zones?

3. Have you considered potential *consumer savings* from regional market mechanisms to support development of larger amounts of renewable resources?
   a. For example, have you considered and even quantified the potential benefits for consumers of a West-wide market for trading unbundled Renewable Energy Credits?
      i. Is this a good idea?
      ii. What should be included and what should be avoided in a market structure to support this?
   b. Another example of a regional market mechanism to support renewable resources is coordination across balancing authorities to facilitate intra-hour trading.
      i. Is this a good idea?
      ii. Have you considered and even quantified the potential benefits for consumers?
      iii. What should be included and what should be avoided in a market structure to support this?
   c. What additional market tools would facilitate more transparent development of renewable resources? What are the barriers to getting these tools in place and potential solutions to get over these barriers?

4. Utilities collaborated on building many of the coal and nuclear plants and transmission in the West.
   a. Is this cooperative model relevant today for developing Western Renewable Energy Zones? Why or why not?
   b. What are the barriers that impede such cooperation today?
   c. Conversely, what conditions create:
      i. Multi-*utility* cooperation for renewable resource development and transmission?
      ii. Multi-*state/provincial* cooperation for renewable resource development and transmission?

5. What would it take for your state/province to allow a utility to:
   a. Jointly develop and own renewable resources with another utility?
   b. Issue similar RFPs based on a model document, or simply coordinate with another utility on the timing of *separate* requests for proposals for the same resource location(s)?
   c. What other models could facilitate development of resources in Western Renewable Energy Zones and transmission to load centers?

d. Are there any barriers to joint ownership with an out-of-state utility/utility outside the province?

6. Besides any Renewable Portfolio Standards, what are the key regulations that affect renewable resource planning and procurement for the utilities you regulate? Do any of these regulations affect the potential for joint or coordinated procurement of renewable resources by multiple utilities, including utilities in other states/provinces? What changes, if any, might need to be made to state/provincial laws and regulations to facilitate coordinated resource procurement?

7. What effect, if any, does utility interest in owning generating facilities vs. buying power have on acquiring resources in Western Renewable Energy Zones? What is the current practice and anticipated trend for renewable resources for utilities in your state/province – owning or buying?

8. To what extent can the commission and the utilities you regulate make decisions that achieve optimal solutions for long-term renewable resource needs, vs. simply keeping rates as low as possible in the near term? To what extent can the commission consider what's best for the public interest generally? To what extent can the commission consider what's best for the region as a whole?

TRANSMISSION PLANNING AND DEVELOPMENT

9. Do any state/provincial policies or regulations impede *interstate* transmission development/transmission development across multiple provinces? If so, please explain and suggest possible solutions.

10. Regarding the transmission planning process in your state/province, particularly for renewable resources:
    a. Are transmission plans submitted to the commission or other state/provincial body for approval and, if so, what is the process for that?
    b. What, if any, coordination is required with other utilities within the state/province and in adjacent states?
    c. Do the transmission plans cover interstate lines/lines across multiple provinces? If so, what do the plans require in that regard?

11. "Right-sizing" can ensure near-term transmission projects are adequately sized to meet long-term needs, reduce requirements for new transmission corridors and minimize environmental disruption.
    a. In cost recovery or any preapproval proceedings, how would the commission view a utility's plan to grow into a transmission line over time, including transmission service for third parties?
    b. Would any statutory or regulatory changes be needed for a utility to right-size transmission lines to access high-quality renewable resources in advance of need?

12. Bonneville Power Administration and merchant transmission developers have used an "open season" process as a way to identify potential transmission partners and fill up a proposed line. For example, one month each year Bonneville accepts requests for new transmission service and aggregates them to plan transmission expansion. A service contract and a deposit equal to 12 months of transmission service are required. Should utilities consider using an open season process to facilitate transmission to renewable resource areas? Why or why not? Are there other models that might work better long term?

13. Does your state have an interest in developing transmission for exporting renewable resources to other states? What would be needed to facilitate exports of renewable resources to other jurisdictions on a transmission line owned by the utility, owned by a utility affiliate, or with a hybrid ownership structure? What are the implications for cost recovery and rate treatment?

14. Do we have the necessary institutional structures in the West to successfully develop transmission to Western Renewable Energy Zones, or do we need a new paradigm? Why or why not? Are any of the following needed:
    a. Regional or subregional planning, for renewable resources, as well as transmission?
    b. Regional cost allocation processes?
    c. A regional transmission authority that can require lines to be built and, if so, what kind of entity would that be?
    d. Institutional structures and processes that are in place in other parts of the U.S.?
    e. Anything else?

FUTURE REGIONAL DISCUSSIONS

15. As part of the Western Renewable Energy Zones project, the Western Governors' Association is planning to convene small groups of utilities and state regulatory commissions to discuss possible coordination of resource procurement from zones of common interest.
    a. Is this a good idea?
    b. How can we make these small discussion groups a productive means of moving from a conceptual plan for coordinated procurement and associated transmission to implementation?
    c. Discussion groups may consider, for example, ways to remove barriers to coordinated procurement from Western Renewable Energy Zones. How could we facilitate agreements in principle between utilities and regulators on such issues, subject to utility management and commission approval?

16. For each of the following topics, would your commission be interested in discussing the topic at a subregional or regional level and, if so, what are the key questions or issues of interest to your commission?
    a. Regional energy efficiency initiatives – for example, transforming regional markets for energy-efficient products such as consumer electronics
    b. Standardizing renewable energy credits that are tradable across the West
    c. Distributed generation, including the potential impact of solar PV on planning for resources, distribution systems and transmission
    d. Future costs of renewable energy generation
    e. Potential effects of carbon limits on resource and transmission development

    Are there other electricity topics that may be of interest to your state for discussion at a subregional or regional level? Please specify the topic and key issues of interest.

<u>Questions for Utility Resource Planners/Procurement Managers</u>

WESTERN RENEWABLE ENERGY ZONES

1. Looking at the model results we sent for your utility, are the top Western renewable energy zones identified for your utility consistent with your analyses for acquisition of renewable resources …
    a. In 10 years?
    b. In 20 years?
    c. If the model results are not consistent with your analyses, where does your utility plan to acquire renewable resources in these two timeframes?

2. Besides cost, why is your utility focusing on the resource locations you identified in the last question (and not on other locations) – for example, existing or planned transmission, resource quality, locations of resources bid into RFPs, risk considerations, diversity of resource type, diversity of hourly profiles to minimize integration costs?

3. Looking at the model results we sent, including *other* utilities that share your top Western Renewable Energy Zones, do you see any potential partners for coordinating procurement of renewable resources and associated transmission?

4. Do you use resource and delivered-cost data from the Western Renewable Energy Zones initiative in your planning or procurement process? If so, how? If not, how could such information be usefully integrated into these processes to explore resource alternatives, and would regulatory changes be required to do so?

RENEWABLE RESOURCE PLANNING AND PROCUREMENT

5. a. What are the issues you struggle with in resource planning and procurement, particularly as they relate to renewable resources?
    b. What are the barriers to efficient planning and procurement for renewable resources?
    c. What changes in federal or state regulations would enable more efficiencies within these processes and as they integrate with each other?

6. Please describe your renewable resource planning process – frequency of plan filings (if any), timeline for development and any stakeholder process, required procedures, and any acknowledgment or preapproval process.

7. Please describe your renewable resource procurement process:
    a. Frequency, RFP timeline, required procedures, and any acknowledgment or preapproval process for resulting bids
    b. What are the key drivers in the selection of renewable resources?
    c. Do you issue technology-neutral RFPs or do you specify the technology that you want – for example, rooftop solar PV?

8. Please describe any current and planned solicitations for renewable resources.

9. What would it take for your utility to:
    a. Jointly develop and own renewable resources with another utility?
    b. Jointly issue a request for proposals with another utility – or issue similar RFPs based on a model document (either of which could lead to joint or separate purchase agreements)?

c. Coordinate with another utility on the timing of *separate* requests for proposals for the same resource location(s)?
d. What benefits do you see, if any, for some sort of coordinated resource development?
e. What other models could facilitate development of resources in Western Renewable Energy Zones and deliver them to load centers?

10. In resource planning, do you evaluate a high carbon cost scenario or high Renewable Portfolio Standards scenario – state or federal? If so:
    a. What levels do you test?
    b. What's the rough *magnitude* of the increase in renewable resource levels compared to your reference or base case?
    c. How do scenarios representing high levels of renewable resources or high carbon costs change the *location* of renewable resources the utility might acquire?

11. How much *distributed* renewable energy (MW, MWh or percent of load) do you forecast in 2020 and 2030, *beyond any distributed generation set-asides* that may exist in state Renewable Portfolio Standards? What type of generation do you expect to see a lot of in the future – for example, rooftop solar PV, utility-scale solar PV, or concentrated solar power systems? What trends do you see in the cost of distributed generation compared with utility-scale renewable generation?

12. How specific is the utility's resource plan in identifying renewable resources the utility plans to acquire in the near term (say, over the next three to five years) vs. the long term (10 years and longer)? For example:
    a. Are resource types like wind and biomass specified? Only for near-term acquisitions?
    b. How specific are renewable resource locations defined in the near term vs. the long term, and what is the basis for any specified locations – for example, bids from RFPs; state, regional or national databases; or state renewable energy zone processes?

13. In resource planning and acquisition processes, how does your utility compare renewable resources within or close to the utility's service area vs. more remote resources that require long-distance transmission?
    a. Does the utility do detailed economic analyses?
    b. When do you see the crossover in cost between adding more transmission to get to remotely located but better-quality renewable resources vs. more local sites with lower quality resources?

14. In your analysis of resource options, do you evaluate the impact of potential increases in available capacity on existing transmission lines that could result from conventional and advanced grid technologies, reduced thermal plant operations, and market mechanisms that facilitate intra-hour transactions?

15. In resource planning and procurement, how do you evaluate the risk of future environmental regulations, including criteria air pollutants and carbon, to continued operation of existing coal plants? For example, does your utility conduct scenario analysis and, if so, what kind of impacts does the analysis indicate?

16. How are you building greater flexibility into your resource portfolio to accommodate the variability of wind and solar?

17. Have you considered potential *consumer savings* from regional market mechanisms to support development of larger amounts of renewable resources?
    a. For example, have you considered and even quantified the potential benefits for consumers of a West-wide market for trading unbundled Renewable Energy Credits?
        i. Is this a good idea?
        ii. What should be included and what should be avoided in a market structure to support this?
    b. Another example of a regional market mechanism to support renewable resources is coordination across balancing authorities to facilitate intra-hour trading.
        i. Is this a good idea?
        ii. Have you considered and even quantified the potential benefits for consumers?
        iii. What should be included and what should be avoided in a market structure to support this?
    c. What additional market tools would facilitate more transparent development of renewable resources? What are the barriers to getting these tools in place and potential solutions to get over these barriers?

FUTURE REGIONAL DISCUSSIONS

18. For each of the following topics, what are the key questions or issues of interest to your utility, does your utility already discuss these issues with other utilities or state regulators – and, if so, in what venues, and would your utility be interested in discussing the topic at a subregional or regional level?
    a. Regional energy efficiency initiatives – for example, transforming regional markets for energy-efficient products such as consumer electronics
    b. Standardizing renewable energy credits that are tradable across the West
    c. Distributed generation, including the potential impact of solar PV on planning for resources, distribution systems and transmission
    d. Future costs of renewable energy generation
    e. Potential effects of carbon limits on resource and transmission development
    f. Are there other topics that may be of interest to your utility for discussion at a subregional or regional level? Please specify the topic and key issues of interest.

<u>Questions for Utility Transmission and Regulatory/Government Affairs Managers</u>

PREFERRED WESTERN RENEWABLE ENERGY ZONES

1. "Foundational" transmission lines are those lines that WECC's 10-year transmission plan assumes will be completed before 2020. They are shown on the maps we provided your utility. To what extent will these foundational lines affect where your utility may acquire renewable resources?

2. The maps we provided also show "potential" transmission lines – lines identified in subregional transmission plans that do not meet the criteria for foundational lines. Which of these *potential* lines do you consider *<u>both</u>* (a) likely to happen and (b) likely to affect your utility's renewable resource procurement?

RENEWABLE RESOURCE PLANNING AND PROCUREMENT

3. Regarding possible subregional planning for renewable resources:
    a. Is there value in coordination of renewable generation planning among utilities on a subregional basis?

   b. What, if any, advantages do you see in utilities coordinating with one another to develop high-quality renewable resources in a common area?
   c. Can subregional transmission planning as it exists today help facilitate potential partnerships for renewable energy development and associated transmission and, if so, how?
   d. How could subregional transmission planning groups specifically address development in Western Renewable Energy Zones?

4. Utilities collaborated on building many of the coal and nuclear plants and transmission in the West.
   a. Is this cooperative model relevant today for developing Western Renewable Energy Zones? Why or why not?
   b. What are the barriers that impede such cooperation today?
   c. Conversely, what conditions create:
      i. Multi-*utility* cooperation for renewable resource development and transmission?
      ii. Multi-*state* cooperation for renewable resource development and transmission?

5. What would it take for your utility to:
   a. Jointly develop or own renewable resources with another utility?
   b. Jointly issue a request for proposals with another utility – or issue similar RFPs based on a model document (either of which could lead to joint or separate purchase agreements)?
   c. Coordinate with another utility on the timing of *separate* requests for proposals for the same resource location(s)?
   d. What other models could facilitate development of resources in Western Renewable Energy Zones and transmission to load centers – for example, feed-in tariffs to stimulate use of transmission to Renewable Energy Zones?

6. Regarding cost recovery for renewable resources and associated transmission:
   a. What factors do you consider in evaluating the likelihood of full cost recovery and profitability?
   b. What changes in the cost recovery process would facilitate development in Western Renewable Energy Zones?

7. Regarding coordination of resource planning and transmission planning:
   a. Does the separation of merchant and transmission functions inhibit in any way coordination of these processes? If so, what problems does it cause and what regulatory changes may be needed to solve those problems?
   b. How is transmission planning coordinated with integrated resource planning at your utility, if at all? For example, what type of information is shared by the utility's transmission function during resource planning?
   c. Conversely, how do integrated resource plans inform transmission planning?
   d. Is planning for renewable resources done far enough ahead to timely inform transmission needed 10 years in the future?

TRANSMISSION PLANNING AND DEVELOPMENT

8. Do any state policies or regulations impede *interstate* transmission development? If so, please explain and suggest possible solutions.

9. Does your utility have adequate transmission over the next 10 years or so to meet foreseeable renewable resource requirements and environmental regulations including carbon and other air

pollutants? If not, what are your plans for addressing this gap?

10. Additional capacity could become available on existing transmission lines through conventional and advanced technologies, reduced thermal plant operations, and market mechanisms that facilitate intra-hour transactions.
    a. How could such changes affect where your utility develops renewable resources, including Western Renewable Energy Zones, and associated transmission?
    b. If future environmental regulations for criteria air pollutants and carbon led to significantly reduced coal plant operations or retirements, could any freed-up transmission capacity be useful for incremental renewable resources? Has your utility done any such analysis?

11. "Right-sizing" can ensure near-term transmission projects are adequately sized to meet long-term needs, reduce requirements for new transmission corridors, and minimize environmental disruption. Would any statutory or regulatory changes be needed for a utility to right-size transmission lines to access high-quality renewable resources in advance of need?

12. What would it take for your utility to jointly develop and own a transmission line with another utility? If your utility has experience planning transmission projects of possible interest to other utilities and resource developers, were there efforts to solicit joint ownership or third-party subscription? If yes, please describe the process, results and lessons learned. If you did not solicit participation by others, what were the reasons?

13. Bonneville Power Administration and merchant transmission developers have used an "open season" process as a way to identify potential transmission partners and fill up a proposed line. For example, one month each year Bonneville accepts requests for new transmission service and aggregates them to plan transmission expansion. A service contract and a deposit equal to 12 months of transmission service are required. Should utilities consider using an open season process to facilitate transmission to renewable resource areas? Why or why not? Are there other models that might work better long term?

14. What interest, if any, does your utility have in developing transmission for exporting renewable resources to other jurisdictions? What would be needed to facilitate exports of renewable resources to other jurisdictions on a transmission line owned by the utility, owned by a utility affiliate, or with a hybrid ownership structure? What are the implications for cost recovery and rate treatment?

15. Do we have the necessary institutional structures in the West to successfully develop transmission to Western Renewable Energy Zones, or do we need a new paradigm? Why or why not? Are any of the following needed:
    a. Regional planning, for resources as well as transmission?
    b. Regional cost allocation processes?
    c. A regional transmission authority that can require lines to be built and, if so, what kind of entity would that be?
    d. Institutional structures and processes that are in place in other parts of the U.S.?
    e. Anything else?

FUTURE REGIONAL DISCUSSIONS

16. As part of the Western Renewable Energy Zones project, the Western Governors' Association is planning to convene small groups of utilities and state regulatory commissions to discuss possible coordination of resource procurement from zones of common interest.
    a. Is this a good idea?
    b. How can we make these small discussion groups a productive means of moving from a conceptual plan for coordinated procurement and associated transmission to implementation?
    c. How can we facilitate the sharing of useful information across utilities, recognizing competitive issues and confidentiality concerns?
    d. Discussion groups may consider, for example, ways to remove barriers to coordinated procurement from Western Renewable Energy Zones. How could we facilitate agreements in principle between utilities and regulators on such issues, subject to utility management and commission approval?

17. For each of the following topics, what are the key questions or issues for your utility, does your utility already discuss the topic with other utilities or state regulators – and, if so, in what venues, and would your utility be interested in discussing the topic at a subregional or regional level?
    a. Regional energy efficiency initiatives – for example, transforming regional markets for energy-efficient products such as consumer electronics
    b. Standardizing renewable energy credits that are tradable across the West
    c. Distributed generation, including the potential impact of solar PV on planning for resources, distribution systems and transmission
    d. Future costs of renewable energy generation
    e. Potential effects of carbon limits on resource and transmission development
    f. Are there electricity topics that may be of interest to your utility for discussion at a subregional or regional level? Please specify the topic and key issues of interest.

Appendix B. Resource Planning and Procurement Processes

This appendix provides links to each utility's most recent integrated resource plans (IRPs) and state/provincial resource planning and procurement regulations.[187] Following that are brief descriptions of each utility's resource planning and procurement processes, including any distinct requirements for renewable resources, based primarily on interviews with utility planning personnel. Also included is a summary of current and planned renewable resource solicitations.

In some states, regulated utilities are simply required to submit an IRP as a compliance filing and the Commission may not take action. Other state commissions may "acknowledge" the IRP. IRP acknowledgment does not guarantee favorable ratemaking treatment for proposed resources. However, in some states IRP acknowledgment is important in cost recovery proceedings. A couple of states approve IRPs, conveying a finding of prudence.

The level of direction by state utility regulators in resource procurement, including requirements for competitive bidding and any acknowledgment or preapproval of resources selected, varies significantly. In some states, resource planning and procurement processes are closely aligned.

[187] For a summary of state IRP policies, see http://www.raponline.org/document/download/id/4447.

Most Recently Filed Utility Integrated Resource Plans[188]

Utility	Year	URL
Arizona Public Service	2009	http://www.aps.com/_files/various/ResourceAlt/APS_2009_Resource_Plan_Report_sFINAL_012909.pdf
Avista	2009	http://www.avistautilities.com/inside/resources/irp/electric/Pages/default.aspx
BC Hydro	2008	http://www.bchydro.com/planning_regulatory/irp/past_plans/2008_ltap.html
Colorado Springs	2008	http://www.csu.org/residential/energy/electric/eirp/item14257.pdf
El Paso Electric (NM)	2011	http://www.epelectric.com/nm/business/public-advisory-group-meetings
Eugene Water & Electric Board	2011	http://www.eweb.org/2011ierp
Idaho Power	2009	http://www.idahopower.com/AboutUs/PlanningForFuture/irp/default.cfm
Imperial Irrigation District	2010	http://www.iid.com/index.aspx?page=264
Los Angeles Department of Water and Power	2010	http://www.ladwp.com/ladwp/cms/ladwp001967.jsp
NV Energy	2010 2009	http://www.nvenergy.com/company/rates/filings/IRP/northIRP.cfm http://www.nvenergy.com/company/rates/filings/IRP/southIRP.cfm
NorthWestern Energy	2009	http://www.northwesternenergy.com/display.aspx?Page=Default_Supply_Electric&item=16
Pacific Gas & Electric	2010	http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/
PacifiCorp	2011	http://www.pacificorp.com/es/irp.html
Portland General Electric	2009	http://www.portlandgeneral.com/our_company/news_issues/current_issues/energy_strategy/irp.aspx
Public Service Company of New Mexico	2008	http://www.pnm.com/regulatory/irp_electric.htm
Puget Sound Energy	2011	http://pse.com/aboutpse/EnergySupply/Pages/Resource-Planning.aspx
Sacramento Municipal Utility District	2004	http://www.smud.org/en/about/Documents/reports-pdfs/draft-integrated-resource-planning-standard.pdf (most recent revision was 2010)
Salt River Project	2010	http://www.srpnet.com/about/pdfx/ResourcePlanFY2011.pdf
San Diego Gas & Electric	2010	http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/
Seattle City Light	2010	http://www.seattle.gov/light/news/issues/irp/
Southern California Edison	2010	http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/
Tacoma Power	2010	http://www.mytpu.org/tacomapower/about-us/integrated-resource-plan.htm
Tri-State	2010	http://www.poweringthewest.org/2010/12/01/tri-state-files-electric-resource-plan-with-colorado-puc/
Tucson Electric	2010	http://www.tep.com/Company/News/ResourcePlanning/ResourcePlanning.asp
Xcel	2010	http://www.xcelenergy.com/About_Us/Rates_&_Regulations/Resource_Plans/PSCo_2011_Electric_Resource_Plan

[188] Information from Lawrence Berkeley National Laboratory, June 2011.

Resource Planning and Procurement Regulations

	Commission Rule/Order on IRP	Commission Rule/Order on Resource Procurement
AZ	http://images.edocket.azcc.gov/docketpdf/0000112475.pdf	http://images.edocket.azcc.gov/docketpdf/0000112475.pdf
BC	http://www.leg.bc.ca/39th2nd/1st_read/gov17-1.htm	http://www.leg.bc.ca/39th2nd/1st_read/gov17-1.htm
CA	http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/117903.htm	http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/117903.htm
CO	http://www.sos.state.co.us/CCR/Rule.do?deptID=18&deptName=700 Department of Regulatory Agencies&agencyID=96&agencyName=723 Public Utilities Commission&ccrDocID=2259&ccrDocName=4 CCR 723-3 RULES REGULATING ELECTRIC UTILITIES&subDocID=55729&subDocName=ELECTRIC RESOURCE PLANNING&version=21	http://www.sos.state.co.us/CCR/Rule.do?deptID=18&deptName=700 Department of Regulatory Agencies&agencyID=96&agencyName=723 Public Utilities Commission&ccrDocID=2259&ccrDocName=4 CCR 723-3 RULES REGULATING ELECTRIC UTILITIES&subDocID=55731&subDocName=RENEWABLE ENERGY STANDARD&version=21
ID	http://www.puc.state.id.us/search/orders/dtsearch.html	http://www.puc.state.id.us/search/orders/dtsearch.html
MT	http://www.mtrules.org/gateway/Subchapterhome.asp?scn=38%2E5.20	http://www.mtrules.org/gateway/RuleNo.asp?RN=38%2E5%2E2010
NM	http://www.nmcpr.state.nm.us/nmac/parts/title17/17.007.0003.htm	http://www.nmcpr.state.nm.us/nmac/parts/title17/17.009.0572.htm
NV	http://www.leg.state.nv.us/nac/NAC-704.html#NAC704Sec9215	http://www.leg.state.nv.us/nac/NAC-704.html#NAC704Sec9482
OR	http://apps.puc.state.or.us/orders/2007ords/07-002.pdf	http://apps.puc.state.or.us/orders/2006ords/06-446.pdf
UT	http://www.rules.utah.gov/publicat/code/r746/r746-430.htm	http://www.rules.utah.gov/publicat/code/r746/r746-420.htm#T1
WA	http://apps.leg.wa.gov/wac/default.aspx?cite=480-100-238	http://apps.leg.wa.gov/wac/default.aspx?cite=480-107
WY	http://psc.state.wy.us/htdocs/electric/ElectricIRPGuidelines7-10.pdf	N/A

Summary of Utility Resource Planning Processes

Arizona Public Service

The Arizona Corporation Commission updated its IRP rules in 2010. The rules require regulated utilities to file a 15-year resource plan every two years. The Commission can acknowledge the plan, and the utility can request approval of specific resource planning actions. Stakeholder input is solicited during the planning process, and there is a second opportunity for stakeholder input if the Commission finds a need for a public hearing on the IRP.

Under the Commission's Renewable Energy Standard and Tariff rules, utilities also must file a renewable resource implementation plan by July 1 each year for Commission review and approval. The plan describes how the utility intends to comply with the rules for the next calendar year. The plans serve a dual purpose of proposing the budget for the next year's acquisitions and providing a five-year outlook for renewable resource procurement.

Avista

Avista conducts an IRP process every two years including a series of public meetings. The Commission typically acknowledges that the IRP meets the requirements of the rules; it is simply a compliance filing.

BC Hydro

The recently enacted Clean Energy Act requires BC Hydro to submit an IRP by December 2011 and every five years thereafter. The IRP is submitted to the Minister for approval by the Cabinet. The utility is conducting a number of internal analytical exercises and operating a number of educational and technical workshops that are open to the public. These workshops solicit feedback from the populace.

Colorado Springs Utilities

Colorado Springs Utilities is required to file an IRP every five years with the Western Area Power Administration (WAPA). At the time of the interview the utility expected to complete its current planning cycle by September 2011.

A mandatory public process involves several public meetings and an advisory group composed of approximately 20 groups including residential, commercial and industrial customers, environmentalists, educational institutions and the military.

A presentation of the IRP to the utility board provides a high-level view of the IRP, including capacity needs, proposed resources and costs and demand-side management options. The board provides feedback and may require changes. The utility sends the board-approved IRP to WAPA.

El Paso Electric

El Paso Electric files an IRP occurs every three years following a year-long series of meetings with New Mexico stakeholders. The Public Regulatory Commission does not take action on the IRP unless a stakeholder challenges the plan. Renewable Portfolio Standards in Texas and New Mexico drive much of the planning requirements for El Paso Electric. The utility also files a renewable resource procurement plan in New Mexico by July 1 each year for Commission approval, identifying the resources the utility plans to acquire to meet the RPS.

Eugene Water and Electric Board
EWEB conducts its planning process in five-year intervals. New renewable resource development opportunities are reviewed based on project proposals presented to the utility.

Idaho Power
Idaho Power engages in an IRP process every two years. The year-long process includes stakeholder input solicited through an IRP advisory council comprised of some 20 members including representatives of each customer class, environmental groups, state agencies, and representatives from the Oregon and Idaho public utility commissions. Advisory council meetings are open to the public and receive fairly good turnout. Once an IRP plan is complete, the utility files it first with the Idaho Commission and then with the Oregon Commission for acknowledgment.

Imperial Irrigation District
Generally, IID conducts an IRP process every one or two years. The IRP is reviewed by management and the governing board, and the board determines whether the plan will go forward. Public input on the plan is provided at regular board meetings. While the utility files its IRP with the California Energy Commission, there is no official approval process.

Los Angeles Water and Power Department
LAWPD's goal is to develop a resource plan every year. A public process every two years solicits stakeholder input.

NorthWestern Energy
NorthWestern Energy must file a resource and procurement plan, including a three-year action plan, with the Montana Commission by December 15 of each odd-numbered year. The utility solicits stakeholder input through its Electricity Technical Advisory Committee, composed of representatives from the commission, the Consumer Advocate, the state Department of Environmental Quality and public interest groups. The utility meets regularly with the committee to discuss the IRP.

NV Energy
NV Energy is required by statute to file an IRP at least every three years. The utility files amendments during the interim years. The utility also is required to file energy supply plan updates with a two- or three-year action plan. NV Energy regularly updates these plans.

As part of the IRP approval process, the Public Utilities Commission approves resource and transmission projects and contracts for long-term power purchase agreements. Regulatory requirements also mandate that any new long-term resource contract be filed for approval at the Commission in an IRP amendment. A robust stakeholder process includes mandated stakeholder workshops and certain procedural steps.

Pacific Gas & Electric
PG&E makes two kinds of filings each year: 1) an annual renewable resource procurement plan that demonstrates how the utility will achieve RPS targets and 2) a backward-looking filing twice annually that shows how the utility is progressing toward these targets. Stakeholder input is part of both processes, but is primarily directed at the long-term planning process. Following Commission acknowledgment of the procurement plan, the utility issues a resource solicitation.

California regulated utilities also must file a long-term procurement plan every two years. The Commission specifies the scenarios and assumptions the utilities must use in their analysis for meeting energy and capacity needs, including a 33 percent penetration level for renewable resources and mandated carbon emission reductions.

PacifiCorp

PacifiCorp files a system-wide IRP using a 20-year planning period every two years in all of the jurisdictions it serves, requesting Commission acknowledgment. IRP requirements vary in each state,[189] as does the importance of the IRP for resource procurement and cost recovery proceedings. Commission review considers how the company met procedural and substantive requirements for resource planning and focuses on the IRP action plan for near-term resource planning activities. The company takes stakeholder input through public input meetings.

Portland General Electric

PGE's resource planning process runs on roughly a three-year cycle; that is, the company must file a new IRP within two years of acknowledgment of the prior plan. The planning process includes public meetings, data requests, development of a preferred resource portfolio for a 20-year planning horizon, and an action plan for near-term resource activities. The Commission acknowledges plans that meet procedural and substantive requirements and that seem reasonable. The Commission may decline to acknowledge a plan or provide direction for improvements that may garner Commission acknowledgment. The Commission also may include requirements for the next planning cycle.

Public Service of Colorado

PSCo must file an IRP every four years and a renewable energy plan every year. These processes have recently been consolidated into the same docket. IRPs use a 30-year planning horizon.

It takes one year to adjudicate input from stakeholders. Intervenors may testify in support of or opposition to the plan or request changes. Plans ultimately must be approved by the Commission.

PSCo's planning process incorporates two phases. The company's phase one filing lays out planning assumptions and a resource acquisition process. The utility then conducts a competitive bidding process. In phase two, PSCo files the results of the acquisition process. An independent evaluator approved by the Commission files a report that analyzes whether the utility conducted a fair bid solicitation and evaluation process, including any deficiencies. The Commission may approve, condition, modify or reject the utility's preferred resource plan. The Commission approves "buckets" of resource types, not specific contracts. PSCo then proceeds with due diligence review and contract negotiations for purchased resources or files applications for Certificate of Need and Public Convenience for proposed utility-owned resources.

Public Service Company of New Mexico

PNM files an IRP with the Public Regulatory Commission every three years following an extensive public engagement process. The Commission does not take action on the IRP unless a stakeholder challenges the plan.

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[189] For a description of the IRP standards in each of the six states PacifiCorp serves, see Appendix B in PacifiCorp's 2011 IRP: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2011IRP/2011IRP-Appendices_Vol2-FINAL.pdf.

The company also prepares an annual renewable procurement plan that describes how the utility will meet RPS requirements over the next two years. In 2011, RPS requirements jumped to 10 percent, up from 6 percent. In 2015 the requirement will reach 15 percent. The 2013 IRP will look to fill renewable resource needs in 2015.

Puget Sound Energy
PSE files an IRP every two years. The process includes significant public involvement. The utility files a draft RFP within 135 days of the IRP filing, typically an all-source solicitation. A 60-day public comment and Commission review period follows. The Commission typically acknowledges that the IRP meets the requirements of the rules; it is simply a compliance filing.

Sacramento Municipal Utility District
SMUD's renewable resource planning process is part of the IRP presented to SMUD's board. It runs on about a three year cycle. SMUD's board has mandated renewable resource targets and the board approves contracts. Roughly quarterly, the board reviews the utility's long-term resource plan and where it stands in relation to its renewable resource targets. SMUD files detailed reports to the California Energy Commission on progress toward renewable resource requirements.

Salt River Project
SRP's renewable resource plan originates from the principles that its board set forth for sustainable resources in 2006.[190] An annual planning process develops resource targets. SRP's board approves resource plans through its budgeting process. SRP is not required to file an IRP with the Arizona Corporation Commission. The utility has periodic stakeholder workshops.

San Diego Gas & Electric
SDG&E files a long-term procurement plan every two years and a renewable resource procurement plan annually.

Seattle City Light
Seattle City Light files an IRP every two years. The timeline for development is about 18 months. The stakeholder process includes large customers, government agencies, suppliers, universities and other constituents. They participate in the development of the plan as well as public meetings. The city council approves the plan.

Southern California Edison
SCE files a resource plan every two years. The horizon for the planning is 10 years. Renewable resource plans are on an annual cycle. The utility has a half dozen procurement programs running on different schedules, some serving narrow niches. Annual solicitations focus on large renewable resource projects to reach the 33 percent RPS target.

Tacoma Power
Tacoma Power has a statutory mandate to prepare an IRP every two years. An IRP update may be submitted in lieu of a complete plan. The mandate encourages, but does not require, public participation, which the utility enables through stakeholder meetings. The plan must be approved by the utility's board of directors.

[190] At the time of the interview, SRP was revisiting these principles with stakeholder input.

Tri-State
Tri-State must file an IRP every three years with WAPA as a condition of its power purchase agreements for federal hydro-power. Tri-State also must file a resource plan with the Colorado Public Utilities Commission as well as annual updates. While Tri-State takes input from stakeholders, as a not-for-profit cooperative its board of directors drives policies.

Tucson Electric
Tucson Electric files an IRP with the Commission every two years for acknowledgment. The IRP uses a 20-year planning horizon.

The company also must file an annual implementation plan with the Commission stating how it intends to meet state renewable resource requirements, an annual compliance filing to update the Commission on previous year activities, and a mid-year filing detailing plans for the upcoming year. The annual plans must be approved by the Commission.

The utility takes stakeholder input in public meetings prior to filing the IRP and the renewable resource implementation plan.

Summary of Resource Procurement Processes

Following are brief descriptions of resource procurement processes for each utility, based primarily on interviews with procurement personnel.

Arizona Public Service
In 2010, the Arizona Corporation Commission approved a rule that formalized previously adopted guidelines on best practices for competitive procurement. The guidelines include acceptable practices, a preference for RFPs and the use of an independent monitor to oversee solicitations. Over the last few years, APS has issued solicitations for renewable resources each year, including three RFPs in 2010. The timeline for RFPs depends on the technology being procured, but on average it takes six to nine months from solicitation issuance until contract execution. Arizona's resource acquisition rules also allow for bilateral contracts outside a competitive bidding process.

Avista
Under the Washington Utilities and Transportation Commission rules for regulated utilities, Avista must submit a proposed RFP and accompanying documentation no later than 135 days after the utility's IRP is due. A 60-day public comment period follows. The Commission approves or suspends the RFP within 30 days after the close of the comment period. The utility must solicit bids for electric power and electrical savings within 30 days of a commission order approving the RFP. Commission staff is present at bid openings.

Avista selects a short-list of all the most promising projects with good, solid developers, good credit, all the requisite permits, and transmission solutions. The Commission does not pre-approve projects.

BC Hydro
While BC Hydro generally needs to have an approved IRP before issuing an RFP, the utility may purchase resources without pre-approval where it has identified a near-term requirement and cannot wait. The utility submits resources selected in the RFP process to the Commission for approval. The Clean Energy Act provides certain exemptions.

Colorado Springs Utilities
The frequency of the utility's procurement process is driven by needs identified in the IRP. The RFP timeline is a function of internal procurement procedures the utility must follow, including keeping the call open for 60 to 90 days. The first step in the evaluation is a technical analysis, followed by a determination of developer capability. The process is then focused on pricing considerations. All bids must be approved by the utility's Chief Energy Services Officer.

El Paso Electric
El Paso Electric files its procurement plan with the Commission in June/July and typically receives approval by December. There is no pre-approval process.

Eugene Water and Electric Board
EWEB has not issued RFPs in the past. Instead, the utility prefers bilateral negotiations after surveying the available development opportunities.

Idaho Power
Idaho Power's IRP includes a near-term action plan identifying the required steps needed to implement its preferred portfolio. Near-term resource needs will typically trigger an RFP process. For utility-owned resources, the utility must file with the Idaho Commission a Certificate for Public Convenience and Necessity. Approval gives the utility some assurance that the procured resource will be allowed into retail rates. Under Oregon's competitive bidding guidelines, the utility must file the RFP for approval or request an exemption.

Imperial Irrigation District
RFPs are issued through the Southern California Public Power Authority or by the utility alone based on results of the IRP process.

Los Angeles Department of Water & Power
LADWP uses a competitive bidding process that occurs about once a year. The last few RFPs have been issued through the Southern California Public Power Authority.

The utility creates a short list for board approval. The city council approves contracts lasting more than three years. LADWP uses a scoring sheet wherein cost is the major driver, however, such factors as the financial stability of the developer and environmental issues also are evaluated. Resource diversity also may be considered.

NorthWestern Energy
The Montana Commission's rules state that utilities should use competitive bidding and negotiations with short-listed bidders to test the market for cost-effective resource alternatives. The rules also encourage involvement from an advisory committee. Further, to the extent a utility does not use competitive bidding, the Commission requires documentation of its judgment on that decision. Montana's RPS plays a role in timing of resource solicitations.

NV Energy
NV Energy runs three renewable resources RFPs each year for: 1) contracts up to 25 years in length; 2) contracts up to 20 years for renewable energy credits from in-state projects; and 3) short-term contracts of three years in length or less. The Commission does not approve the RFP document itself. All long-term

contracts must be approved by the Commission. Contracts three years or less must be approved in a Deferred Energy Rate Case.

Pacific Gas & Electric
PG&E generally conducts annual RFPs, approved by the Commission before issuance. An independent evaluator monitors whether the utility followed the proper protocol and whether bidders were treated fairly. The Commission approves each contract. Key factors in the selection process are cost and project viability.

PacifiCorp
Resource procurement requirements vary by state. Utah has the most specified process. The Energy Resource Procurement Act (Utah Code Section 54-17-101) requires PacifiCorp to conduct a solicitation for significant energy resources – those consisting of 100 MW or more of new generating capacity and lasting 10 or more years. The solicitation and the selected resources must be approved by the Commission as compliant with the law and in the public interest, considering whether it will most likely result in the lowest reasonable cost to retail customers. Renewable resources 300 MW or less are subject to a modified process.[191]

The Oregon Commission's competitive bidding guidelines apply to resources 100 MW or greater and five years or longer. The Commission approves the RFP and the independent evaluator whose job it is to evaluate whether all offers are treated fairly. The process can lead to Commission acknowledgment of a final short-list of bidders. The portfolio modeling and decision criteria used to select the final short-list of bids must be consistent with those used to develop the utility's acknowledged IRP action plan. A utility may apply for an exception to the RFP requirement.

PacifiCorp also serves the states of Washington, Idaho, Wyoming and California. See listings for other utilities serving these states for resource processes in these jurisdictions.

Portland General Electric
PGE's competitive bidding requirements follow the Oregon Commission's requirements described above.

Public Service of Colorado
PSCo typically issues an RFP every four years. However, an RFP may be issued to take advantage of expiring federal tax credits or market conditions or when necessary to meet loads. The competitive solicitation process is intertwined with the resource planning process. If PSCo acquires resources in conjunction with the approved resource plan, there is a presumption of prudence. PSCo looks ahead 6 to 10 years for acquisitions.

Public Service Co. of New Mexico
There is no requirement for a formal procurement process for PNM, but a competitive bidding process is necessary to demonstrate that the utility considered all reasonable alternatives. Processes are conducted on an as-needed basis.

[191] See Utah Code Section 54-17-502 at http://le.utah.gov/~code/TITLE54/htm/54_17_050200.htm.

Puget Sound Energy
PSE's procurement process begins within 135 days of filing the IRP with the Commission. Typically, the utility issues all-source RFPs. The utility also considers market opportunities outside the formal RFP process.

Salt River Project
SRP has used both RFPs and bilateral contracts for procuring renewable resources. SRP board approval is required for contracts.

San Diego Gas & Electric
SDG&E prepares an annual renewable resource procurement plan prior to issuance of an RFP. A number of other mechanisms procure additional renewable resources for California: a feed-in tariff for small, eligible combined heat and power facilities, a new Renewable Auction Mechanism for resources up to 20 MW, and solar PV programs.

Seattle City Light
SCL issues an annual RFP, winnows down bids using primarily cost-driven filters, then focuses on a handful of potential deals and begins due diligence. The city council approves contracts. The utility submits an ordinance package to the mayor's office for review. The mayor's office then formally requests action by the city council. A SCL review committee conducts an initial review before a formal council vote.

Sacramento Municipal Utility District
SMUD has an IRP Steering Committee that evaluates all active resource proposals. Board approval is required for all resource contracts. SMUD has not issued a competitive solicitation for renewable resources for several years, primarily because the company already is meeting its RPS obligations. Future solicitations may be targeted by resource type.

Southern California Edison
With the exception of the fixed-price, feed-in tariff for small combined heat and power units, all resources are procured through competitive bidding. The Commission must pre-approve all contracts in order for the utility to get cost recovery.

Tacoma Power
Tacoma Power issues RFPs every two years or less. The RFP process takes several months. The utility must follow the city of Tacoma's procurement process, which includes standardized forms and standardized requirements. Board approval is acquired for major expenditures.

Tri-State
Tri-State issues RFPs as needed to serve its member utilities. The key themes are cost, affordability and operability. Tri-State serves utilities in five control areas, so the resource is considered in context with the rest of its fleet and the host control area.

Tucson Electric
Tucson Electric issues resource solicitations annually. Generally speaking, it takes 18 months from RFP issuance to final contract negotiations. The utility uses a standardized RFP. An independent third party monitors the process. There is no pre-approval process for bids, although the concept is under

development. As technologies mature, the company anticipates minimum bid requirements to isolate legitimate projects for consideration.

Solicitations for Renewable Resources

The following table presents information utilities provided in the interviews about current and planned solicitations for renewable resources. ("NA" indicates the utility did not address this point in the interview or the RFP did not specify the amount of energy sought.) Additional details for some utilities are listed below the chart.

Current Renewable Resource Solicitations
(Interviews December 2010-April 2011)

Utility	Type of Resource	Timing of Procurement	Amount Sought
Arizona Public Service	Small generators	Currently underway and another in April 2011	2 MW to 15 MW projects for a total of 200,000 MWh/year
Avista	Misc. renewables	2014	NA
BC Hydro	No imminent procurement planned		
Colorado Springs Utilities	Awaiting the results of IRP process		
El Paso Electric	Small solar	Currently underway	2 MW
Eugene Water & Electric Board	No imminent procurement planned		
Idaho Power	Upgrading utility-owned hydro plant		
Imperial Irrigation District	Misc. renewables, excluding geothermal	Currently underway	NA
LADWP	Recent solicitation under review		
Northwestern Energy	Recent solicitation under review		
NV Energy	Misc. renewables, long-term	December 2010 (annually)	Varies
	Misc. renewables, short-term	December 2010 (annually)	Varies
	Renewable energy credits	October 2010 (annually)	Varies
PacifiCorp	Solar	January 2011	2 MW
	Large--scale renewables	2017-2018	NA
Pacific Gas & Electric	Solar PV	2011	500 MW
Public Service of Colorado	Wind	Currently underway	200 MW
	Rooftop Solar	Annual	20-30 MW/year
Public Service of New Mexico	Misc. renewables	2013	NA
Portland General Electric	Misc. renewables	2012	NA
Puget Sound Energy	Building utility-owned wind farm; additional renewable resources considered in 2011 RFP		
Salt River Project	Solar PV	Currently underway	100 MW (in 5-20 MW projects)
Southern California Edison	Solar PV	March 2011	NA
San Diego Gas & Electric	Awaiting Commission approval of 2010 RFPs		
Seattle City Light	Misc. renewables	Annually in September	NA
Sacramento Municipal Utility District	No imminent procurement planned		
Tacoma Power	No imminent procurement planned		
Tri-State	Misc. renewables	2015-2016	NA
Tucson Electric Power	No imminent procurement planned		

- **Arizona Public Service:** APS is undertaking a three-year program seeking to acquire 200,000 MWh/year of renewable resources on a long-term basis. The procurement, taking place in three, one-year allotments, is seeking smaller generators (2 MW to 15 MW individual facility size). APS selected a 100 MW wind project in the first phase of the procurement in 2010. The second procurement was scheduled for April 2011, and a third RFP was planned for 2012.
- **Avista**: Washington's RPS requires the utility's electric loads to be served by renewable resources in the following amounts: 3 percent in 2012-2015, 9 percent in 2016-2019, and 15 percent thereafter. Avista will meet the 2012-2015 targets with incremental hydropower.
- **Colorado Springs Utilities**: Colorado Springs is engaged in its IRP process. While the utility does not need any additional renewable resources at this time, the IRP may reveal a need on which the utility will take action in the future.
- **El Paso Electric:** El Paso just completed procurement of 49 MW of solar capacity and is considering a future RFP for biomass resources.
- **Idaho Power:** Idaho Power is upgrading one of its existing hydropower plants from 12.5 MW to approximately 64 MW.
- **Imperial Irrigation District:** The utility recently completed an RFP for geothermal resources.
- **Northwestern Energy:** The utility is reviewing the results of a solicitation from the fall of 2009 and is negotiating contracts with developers. Northwestern Energy is seeking turnkey projects the utility would own, operate and place into the rate base. The company is reviewing a variety of project sizes.
- **NV Energy:** NV Energy conducts three solicitations annually: long-term resources, short-term resources, and in-state, unbundled renewable energy credits. The utility does not have a set MW requirement for these solicitations.
- **PacifiCorp:** PacifiCorp's solar RFP, completed in January 2011, was the utility's first technology-specific RFP for renewable resources. The utility does not expect to issue its next solicitation for large-scale renewable resources until 2017-2018, due to banking of sufficient renewable energy credits to meet state RPS requirements. The preferred portfolio in the company's recently filed IRP includes incremental wind resources in Wyoming in the following amounts: 300 MW of in 2018, 300 MW in 2019, 200 MW in 2020, and 1,300 MW of additional wind resources by 2030.
- **Pacific Gas & Electric:** The utility's solar PV procurement is targeting 500 MW of resources, with individual project sizes up to 20 MW, seeking half from power purchase agreements and half as utility-owned resources. In the first quarter of 2011, the utility planned on issuing RFPs for the first 50 MW tranche of the 500 MW target. The remaining solicitations will take place throughout the balance of 2011.
- **Public Service of New Mexico:** The utility's renewable energy procurement plan is under review by the Public Regulation Commission, and the company is awaiting an order determining whether the plan has met the "reasonable cost threshold" standard. If the Commission decides the plan meets the standard, PNM would be looking at 2013 for its next procurement. If approval is not given, the utility will issue an RFP shortly thereafter.
- **Portland General Electric:** The utility plans to release an RFP by the end of 2012 for renewable resources to come on-line in 2013.
- **Puget Sound Energy:** The utility is building a large wind farm in southeastern Washington that is expected to meet its renewable resource obligations through 2019. However, additional renewable resources are being considered in the company's 2011 RFP.

Appendix C. State and Provincial Renewable Energy Zone Processes

Alberta, Arizona, British Columbia, California, Colorado, Nevada, New Mexico and Utah have conducted their own assessments of renewable energy resources, focusing on developing resources within their jurisdictions.[192] Some of these processes include planning for transmission that would be required to bring these resources to load centers. Following is a brief description of each of these efforts, along with views from state utility regulators and provincial energy ministries on how these processes affect resource and transmission development.

Alberta – The Provincial Energy Strategy[193] identified areas of renewable and low emission generation for development and established the need for transmission to these zones. Based on this strategy, Bill 50[194] directed construction of transmission to these areas. The provincial government specified the locations, types, and sizes of lines to access these areas and established a 20-year plan for building critical transmission infrastructure. The Alberta Electricity System Operator (AESO) can specify other transmission requirements and is working with regulators on the process for selecting actual transmission pathways. A Transmission Facility Cost Monitoring Committee reports to the Energy Minister. To the extent merchant developers build to these areas, the AESO will not direct transmission facility owners to do so.

Arizona - In 2006, utilities were ordered to draw REZs as part of the Biennial Transmission Assessment (BTA) process overseen by the Arizona Corporation Commission. While the BTA process has been effective, it has not yet accomplished the goal of developing *regional* transmission for renewable resources.

In 2008, as part of the fifth BTA, the commission ordered utilities to identify their top three energy transmission lines for renewable resources and to make proposals to the commission to develop these lines, as well as financing mechanisms to build them. The Commission just completed its sixth BTA.

The Arizona Renewable Resource and Transmission Identification Subcommittee also has identified state REZs. The purpose of ARTIS was to gather, review and map renewable resource and environmental sensitivity data for the state of Arizona and to provide input and support to the Renewable Transmission Task Force's transmission planning efforts. The subcommittee established areas in the state for utility-scale solar and wind development and defined and mapped environmentally sensitive areas.

British Columbia – Under a statutory requirement, BC Hydro's current IRP process is taking a 30-year look at transmission build-out options under various scenarios, considering zones of high-quality renewable resources and sequencing transmission development to access these zones. BC Hydro will report its findings by year-end 2011.

California – The California Renewable Energy Transmission Initiative (RETI) is a statewide planning process that identifies transmission projects needed to meet the state's renewable energy goals – specifically to identify transmission facilities likely to be required to meet a 33 percent RPS requirement by 2020. The initial phases of the RETI project identified Competitive Renewable Energy Zones (CREZs)

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[192] The California Renewable Energy Transmission Initiatives includes out-of-state resources, but the objective is to meet state renewable energy targets.
[193] *See* http://www.energy.alberta.ca/Org/pdfs/AB_ProvincialEnergyStrategy.pdf.
[194] *See* http://www.assembly.ab.ca/ISYS/LADDAR_files/docs/bills/bill/legislature_27/session_2/20090210_bill-050.pdf and http://www.energy.alberta.ca/Electricity/1773.asp.

that hold the greatest potential for cost-effective and environmentally responsible renewable development. The RETI Phase 1B report ranked CREZs according to cost effectiveness, environmental concerns, development and schedule certainty, and other factors to provide a renewable resource base-case for California.

Data from RETI are directly incorporated into the California Public Utilities Commission's long-term procurement planning process. The Commission developed four planning scenarios that utilities model for this process. The scenarios use RETI's cost and resource potential estimates, as well as RETI's approach to valuing resources. The Commission also relies on RETI resource potential figures when permitting transmission and benchmarking resource costs for power purchase agreements.

Colorado – In 2007, the Colorado Legislature passed a bill requiring the state to identify and map its best renewable resource areas.[195] SB 100,[196] also passed that year, required utilities under PUC jurisdiction to identify where development of "beneficial energy resources" required new transmission, to plan for that transmission, and to file applications for approval with the PUC every two years, starting in 2009. The statute also required the PUC to allow utilities to earn profits on transmission construction work in progress and to put transmission expenditures into rates immediately on incurring them.

When utilities submit a certificate of public convenience and necessity to the PUC for a transmission line, they must demonstrate need. That can be difficult for a line designed to support renewable resource projects. The law encourages, but does not require, utilities to build transmission to REZs, and the zones are considered in the PUC's determination of need.

As the renewable resource requirements in the state's RPS ramp up over time, utilities are building to the state zones sequentially. Public Service of Colorado (PSCo) has an application at the commission to build transmission to a zone that is suitable for solar (San Luis Valley). The commission's approval of the line is under appeal and litigation is expected to continue for some time. PSCo chose 250 MW of solar in the last acquisition process, based on the San Luis Valley line being built. However, contracts will not be completed until transmission is available. PSCo has since withdrawn as a sponsor of the line.

The commission expects a second transmission application, filed jointly by three utilities including PSCo, for transmission to the southeast part of the state. The line would reach multiple state REZs.

New Mexico – The state's Renewable Energy Transmission Authority[197] (RETA) was established in 2007 as a quasi-governmental agency to help facilitate the transmission, storage and use of renewable energy. As part of that effort, RETA is in the process of developing maps of existing and potential transmission lines and highlighting potential transmission corridors for exporting renewable energy.[198] Discussions also are underway on a wind collector system in the central-eastern part of the state.

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[195] SB07-091, http://www.puc.nh.gov/Transmission%20Commission/Transmission%20Infrastructure/Appendix%20D.pdf; resulting report, *Connecting Colorado's Renewable Resources to the Markets: Report of the Colorado Senate Bill 07-091 Renewable Resource Generation Development Areas Task Force*, at http://rechargecolorado.com/images/uploads/pdfs/23158d65cf0c2de7be220e35d1f7b72a.pdf.

[196] *See* http://www.dora.state.co.us/puc/rulemaking/SB07-100/SB07-100_enr.pdf.

[197] *See* http://www.nmreta.com/.

[198] *See* http://www.nmreta.com/images/stories/pdfs/reta_draft_corridors_third_iteration.pdf and http://www.nmreta.com/images/stories/pdfs/white_paper_on_long_range_statewide_transmission_plan.pdf.

Nevada – State law requires the Public Utilities Commission of Nevada to designate REZs.[199] Utilities must include in their IRPs a plan for construction or expansion of transmission facilities to serve REZs and to facilitate meeting the state's energy portfolio standard. It is insufficient for a utility to simply propose to build a transmission line to these zones. Instead, the utility must demonstrate a high likelihood that renewable energy facilities will be developed in association with the line.

The Commission can accept or reject the utility's preferred IRP, including transmission. If the commission accepts the plan, the utility has *de facto* prudence approval.

To date, the REZ designations have not had a strong effect on the way utilities plan resources and transmission.

Utah - The Utah REZ process mapped out the types, locations and quality of resources within each zone, with significant stakeholder input. The zones add transparency to the utility's IRP process regarding resource and transmission alternatives and resource cost assumptions. The process brought to light additional information needed for estimating geothermal resource costs.

[199] *See* NAC 704.880, http://www.leg.state.nv.us/NAC/nac-704.html#NAC704Sec880. *Also see* NRS 704.741: "Renewable energy zones" means specific geographic zones where renewable energy resources are sufficient to develop generation capacity and where transmission constrains the delivery of electricity from those resources to customers."

Appendix D. Distributed Generation: State RPS Provisions and Utility Forecasts

Utility	Distributed Generation (DG) Provisions in State Renewable Portfolio Standards[200]	Forecasted Amount of Renewable DG
Arizona Public Service	4.5% DG by 2025, half residential	NA
Avista	ID – None WA – 2x multiplier for DG	NA
BC Hydro	No RPS; under BC's Clean Energy Act, at least 93% of electricity is generated from clean or renewable resources[201]	NA
Colorado Springs	3x multiplier for solar installed before July 2015	NA
El Paso Electric	NM – 4% solar electric by 2020, 0.6% customer-sited DG by 2020 TX – 2x multiplier for all non-wind resources	5-10% of load
Eugene Water & Electric Board	None	Similar to current levels
Idaho Power	ID – N/A OR – Idaho Power's share of state's 20 MW by 1/1/20 solar PV requirement is 500 kW[202]	NA
Imperial Irrigation District	None	NA
Los Angeles Department of Water & Power	None	Approx. 400 MW over several years
Northwestern Energy	None	*De minimis*
NV Energy	Statutory budget mechanism requires utility to spend up to $255 million on solar PV through June 2021	30 MW (with a 1% peak load cap equaling 75 MW)
PacifiCorp[203]	UT – None ID, WY – N/A OR – PacifiCorp's share of state's 20 MW by 1/1/20 solar PV requirement is 8.7 MW[204] WA – 2x multiplier for DG	NA

[200] Unless noted otherwise, information in this column is from Galen Barbose, Ed Holt and Ryan Wiser, "Supporting Solar Power in Renewables Portfolio Standards: Experience from the United States," October 2010, http://eetd.lbl.gov/ea/emp/reports/lbnl-3984e-ppt.pdf.

[201] Biomass, biogas, geothermal heat, hydro, solar, ocean, wind or any other prescribed resource. *See* http://www.leg.bc.ca/39th2nd/1st_read/gov17-1.htm#section1.

[202] *See* ORS 757.370 and 757.375, http://www.leg.state.or.us/ors/757.html; Oregon PUC Order No. 10-200, http://apps.puc.state.or.us/orders/2010ords/10-200.pdf; project sizes between 500 kW and 5 MW (AC); 2x multiplier for PV installed before 2016. In addition, Oregon's feed-in tariff pilot program is designed to incent a total of 25 MW of solar PV by 3/31/15, with individual project sizes up to 500 kW. Utility shares of this total are: Idaho Power – 400 kW, PacifiCorp – 9.8 MW and PGE -14.9 MW. *See* ORS 757.365, http://www.leg.state.or.us/ors/757.html; Oregon PUC Order No. 10-198, May 28, 2010, http://apps.puc.state.or.us/orders/2010ords/10-198.pdf.

[203] PacifiCorp recently engaged Cadmus Group to perform an assessment of system-wide potential for demand-side and "supplemental" resources, including on-site solar and combined heat and power (CHP) systems, by 2030. The analysis found 4,729 average megawatts (aMW) of technical potential for on-site solar electric generation and 747 aMW for CHP systems fueled with biomass or biogas. (One average megawatt is one megawatt of capacity produced continuously over a period of one year. 1 aMW = 1 MW x 8,760 hours/year = 8,760 megawatt-hours.) The reported *achievable* technical potential is far lower "due to low awareness of technologies and other permitting, siting, and/or interconnection concerns": 8 aMW for on-site solar and 130 aMW for biomass/biogas-fueled CHP. *See* pp. 76-77 of the report, *Assessment of Long-Term, System-Wide Potential for Demand-Side and Other Supplemental Resources: Volume I,* March 31, 2011, http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Demand_Side_Management/DSM_VolumeI_2011_Study.pdf.

[204] *See* Oregon regulations listed above.

Utility	Distributed Generation (DG) Provisions in State Renewable Portfolio Standards[200]	Forecasted Amount of Renewable DG
Pacific Gas & Electric	None[205,206,207]	State Clean Energy Future implementation plan targets 5,000 MW of renewable DG statewide by 2020[208]
Portland General Electric	PGE's share of state's 20 MW by 1/1/20 solar PV requirement is 10.9 MW[209]	20-25 MW over 10 years
Public Service of Colorado	3% DG by 2020 (half from retail DG)	3% of load by 2020
Public Service of New Mexico	4% solar electric by 2020, 0.6% customer-sited DG by 2020	65 MW by 2020 and another 65 MW by 2030
Puget Sound Energy	2x multiplier for DG	*
Sacramento Municipal Utility District	None[210]	*De minimis*
Salt River Project	None[211]	*
San Diego Gas & Electric	None[212]	*
Seattle City Light	2x multiplier for DG	6 MW
Southern California Edison	None[213]	2,000 MW by 2020
Tacoma Power	2x multiplier for DG	*De minimis*
Tri-State	CO – 3% DG by 2020 (half from retail DG), 3x multiplier for co-ops and municipal utilities for solar installed before July 2015 NM – 4% solar electric by 2020, 0.6% customer-sited DG by 2020 WY – None	*
Tucson Electric Power	4.5% DG by 2025, half residential	150 MW by 2020 and 300 MW by 2030

[205] California has no set aside for DG in its RPS, however, other California initiatives encourage DG. For example, a feed-in tariff allows eligible renewable resources 1.5 MW or less to sell electricity to investor-owned utilities at a pre-determined price, on a first-come, first-served basis, up to a preset amount. Through the new Renewable Auction Mechanism, the California PUC directed investor-owned utilities to procure a total of 1,000 MW of distributed generation, up to 20 MW per project, over two years. *See* Rulemaking 08-08-009 at http://docs.cpuc.ca.gov/proceedings/R0808009.htm.

[206] For long-term procurement plans the California PUC directed the utilities to model several scenarios for meeting the 33 percent RPS standard, including a scenario with high levels of solar PV.

[207] On May 11, 2011, PG&E issued an RFO for bundled energy and capacity from Eligible Renewable Resources and Renewable Energy Credits. PG&E also is soliciting ownership offers, including build-own-transfers and sites for development. *See* http://www.pge.com/b2b/energysupply/wholesaleelectricsuppliersolicitation/renewables2011/index.shtml. The minimum eligible project size is 1.5 MW. The procurement is for up to 1 percent to 2 percent of PG&E's retail sales volume or approximately 800,000 to 1,600,000 MWh per year. Assuming a capacity factor of 25 percent for variable energy resources, PG&E could procure up to 800 MW of capacity.

[208] PG&E referred to this statewide target in the interview. *See* http://www.cpuc.ca.gov/NR/rdonlyres/ED820DFE-46A3-40A8-8E84-F728BC94DCA5/0/CleanEnergyFuture092110.pdf. Gov. Brown's goal is 12,000 MW of renewable DG by 2020. *See* http://www.energy.ca.gov/2011_energypolicy/documents/2011-05-09_workshop/presentations/02a_Off_of_Gov_Picker_5-9-11.pdf.

[209] See Oregon regulations listed above.

[210] SMUD offers a feed-in tariff program and other incentives for distributed renewable resources.

[211] The Arizona Corporation Commission established renewable requirements by rule. SRP is not among the covered utilities.

[212] SDG&E noted that it has about 100 MW of rooftop solar PV in place and under state requirements must procure about 300 MW. SDG&E also just issued an RFO for renewable resources, with a focus on power purchase agreements and renewable energy credit purchases to fill near-term needs for deliveries in 2011, 2012 and 2013, as well as agreements to fill needs in 2014 and beyond. *See* http://www.sdge.com/documents/rfo/renewable2011/2011RFODocument.pdf. The net contract capacity must be at least 1.5 MW if the facility is within the SDG&E service area or 5 MW if outside the service area.

[213] SCE's recent RFP focused on generating facilities that can connect to existing or planned transmission lines. Minimum project size is 1.5 MW. Project terms vary from very short-term to 20 years, depending on product. *See* http://www.sce.com/EnergyProcurement/renewables/2011-request-for-proposal.htm?from=renewrfp.