

# Smith River Rancheria

## Development of an Energy Organization Investigation

August 27, 2007

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# *Smith River Rancheria Development of an Energy Organization Investigation*

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## Introduction -

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Smith River Rancheria (SRR), for some time, has had a strong commitment to attaining energy self-sufficiency, to reduce overall energy costs and concurrently initiate economic development within the community. Early on it was recognized that the development of an energy organization was important and for this reason was made part of the SRR's strategic review not only for economic development but also the reduction of energy costs. Towards this end, SRR retained Werner G. Buehler of W.G. Buehler & Associates to investigate the many phases or steps required to establish such an energy organization and determine, if in fact, it could benefit the Tribe. The basic phases are delineated as:

1. Identify potential sources of wholesale power and transmission paths
2. Evaluating the various forms of energy organizations
3. Determining the benefits (and disadvantages) of each form of organization
4. Gathering costs to organize and operate the selected form or energy organization
5. Performing an economic analysis of forming and operating an energy organization
6. Develop an implementation plan

## Historic Wholesale Power

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The world or say, the market for wholesale power has changed dramatically during the past 10 years. Historically, the electric utility industry had been a “vertically integrated” monopoly. This meant that the power companies built and developed their own sources of electricity, built and operated their own transmission systems and of course, built and operated their own delivery or local distribution systems. In this way, the electric utilities which had the statutory responsibility for the delivery of power to the end user, 24/7, had complete control of the product development and its delivery.

Traditional electric utilities were monopoly based because they had a statutory obligation to serve customers. And because they had this “obligation to serve” regulatory entities such as state Public Utility Commissions allowed the utilities to charge rates which insured they would receive both a return of and on the capital invested to serve end use customers.

However, this “regulatory compact” changed recently as the result of changes in Federal Legislation. An evolving lineage of Federal legislation inclusive of PURPA – 1978, Epact – 1992, State Retail Choice – 1994/5, FERC Orders 888/889 – 1996, FERC Order 2000 – 1999 and the Energy Policy Act – 2005 increasingly provided both end users and utilities with more options and more risks associated with power production.

## Wholesale Power Today

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Today, because of the aforementioned evolution of utility regulation, in some states end-users can actually choose who they purchase their power from. In other states, end-users or retail customers cannot choose. In those states where “retail choice” is not available, the serving electric utilities can choose who they purchase their wholesale power from, either their own utility generation project, the electrical output of another utility’s generation project, the electrical output from a project owned and developed by investors (non-utility affiliated projects), Federal power sources like hydro-electricity from Federally owned and operated dams and of course the open market.

All of these options are contingent upon availability and price. Availability has much to do with a utility’s legal ability to access certain power projects and the availability of transmission paths and capacity. Prices for wholesale power are conditioned by contract and of course, if purchases are made from the market, the market will dictate the price. As one can see, wholesale power today, its availability and cost is more a function of the market than a guaranteed return on investment as it has been in the past. Today, state regulatory bodies conduct a “prudence review” to determine if a utility acted in a prudent manner when they made the commitment for generation. If so, the cost of the generation and/or generation project is included in the utility’s rates for cost recovery.

## The New Participants

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Most recently, Independent Power Producers (IPP) are investing more into increasing the nation's electrical capacity than the traditional electric utilities. IPPs build and operate "merchant generation" for profit. They have no utility obligation to serve any end-users of electricity and their entire priority is to maximize profit and minimize their investment. IPPs tend to utilize natural gas as the preferred fuel type and use available transmission for their profit; totally independent to any utility's native electric load. It is best to keep in mind that given these incentives, the IPP primary objective is bottom line profit.

Closely associated with the IPP, because of their profit motive, are the Power Marketers and/or Power Brokers. They differ from the IPPs because they are generally traders and not hard asset owners. It is their goal to maximize profit and of course, minimize investment. Power Marketers and Brokers are not unlike stock brokers. They trade power contracts and take advantage of the imperfections in the various power markets. Additionally, they often speculate in transmission contracts in an effort to "add value" to an existing contract for power.

Needless to say, the Power Marketers and/or Power Brokers profits are based upon their ability to forecast and take advantage of market volatility. Enron was the "poster child" for power marketing. Because of the evolving regulatory structure in the electric utility industry in the 1994 to 2000 time period the conventional wisdom was to buy from the power marketers because owning hard generation assets were too risky. However, the Enron debacle showcased the risks associated with power marketing/brokering. More power marketing firms went under; Dynegy, Aquila, Williams, Calpine and AES proving that the power marketing/brokering option was not the panacea the electric industry was seeking.

## Future Power Supply Considerations

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Any electric utility should pursue the following primary goals as they relate to power supply:

1. - Low Cost

"Is this generation source's price competitive in today's market?"

2. - Stability

"Will this generation source stay price competitive into the future?"

3. - Reliability

"Will this generation source always deliver as planned?"

4. - Long-term

"How long will this generation source be available and at what price?"

5. - Accommodates growth

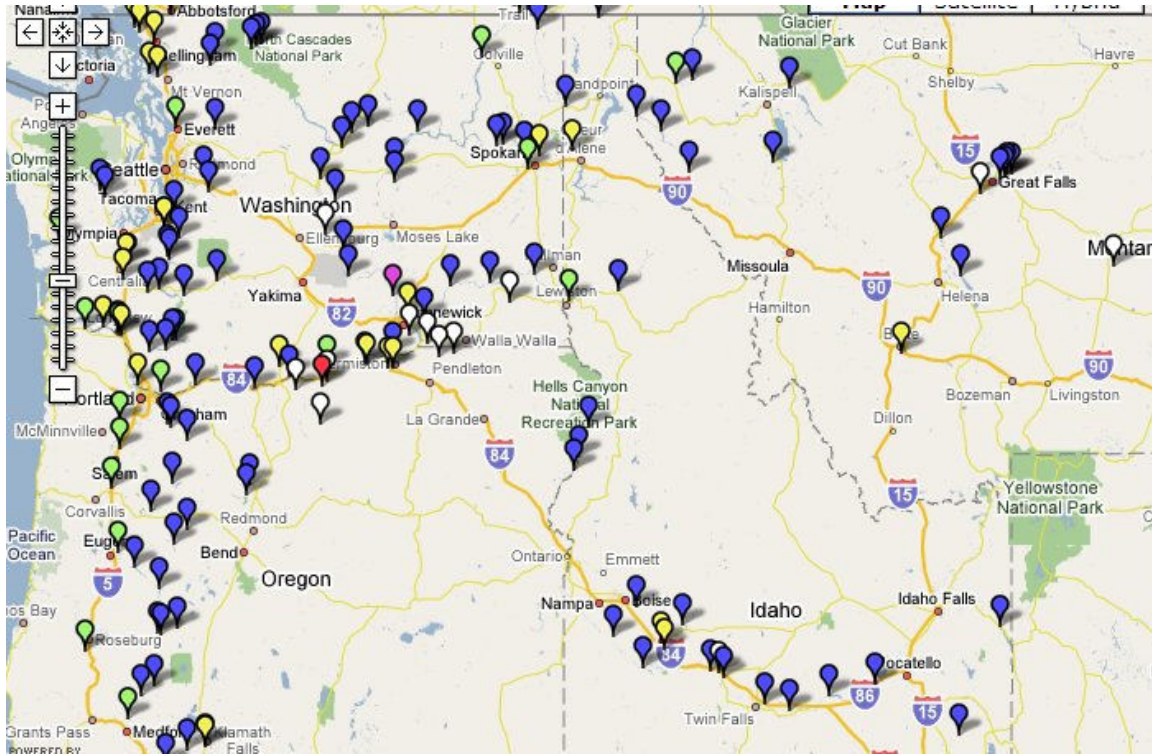
"How flexible is this generation source in its ability to grow increments of power for future load growth?"

As is the case with any portfolio of investments whose value fluctuate in active market, diversification is the “hedge” against the volatility of the unforeseen in the market. Many utilities today are seeking avenues to better diversify their generation portfolio by investing in many, various different projects and products. No utility entity today can afford to put “all their eggs in one basket”.

Every generation portfolio has a certain amount of risk; listed below is short representative list of such risks:

1. - Operating risk -  
“Will the project be operated in the manner it was designed?” -
2. - Performance risk -  
“Will the project/technology perform as predicted?” -
3. - Fuel supply/price risk -  
“Will the fuel source be sufficient and within price tolerances?” -
4. - Volumetric risk -  
“Will the project produce sufficient volume of output to amortize fixed costs?” -
5. - Credit risk -  
“Will the project participants actually pay and pay on time?” -
6. - Political risk -  
“Will increased environmental concerns result in large unforeseen costs?” -
7. - Capital risk -  
“Will the project participants have their share of capital to contribute when needed?” -

## Northwest Generation Locations



**Red = Coal**  
**Green = Biomass**  
**White = Wind**

**Blue = Hydropower**  
**Pink = Nuclear**  
**Yellow = Natural Gas**

There is no question that every generation portfolio has a different risk profile and every utility entity has a different tolerance for risk dependant upon its relative financial health. It is important that those responsible for generation resource planning for a utility discipline their generation acquisitions into short-term, mid-term and longer-term planning in an effort to minimize risk even further. Should the majority of decisions be made contingent upon short-term needs of the utility (3 to 5 years) then by the time 15 to 20 years have passed the utility may find itself out in the market, on the wrong side of the market being long or short; either one could result in significant economic consequences.

## Transmission and the New World of Transmission Access

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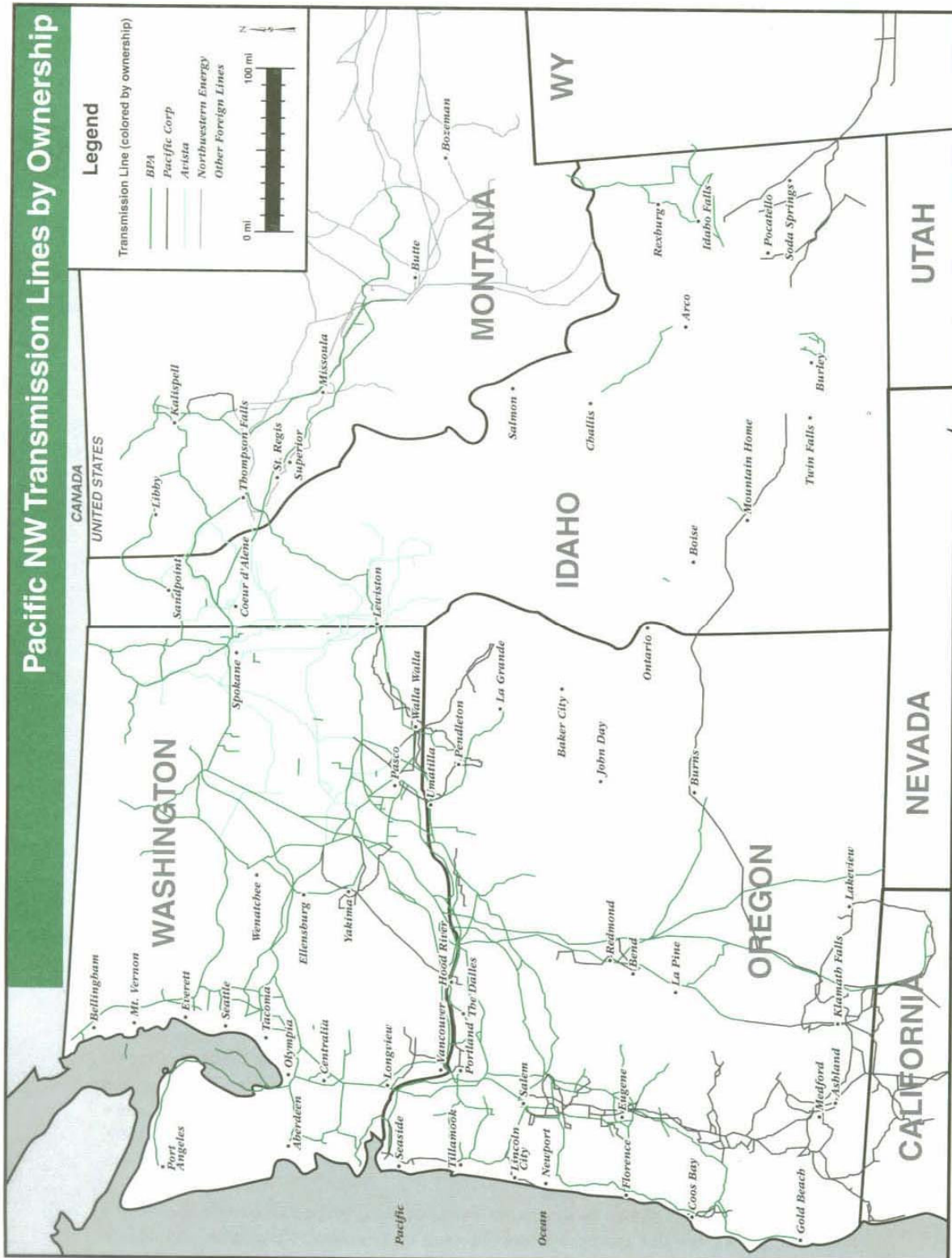
Low cost generation is of no use if you cannot get the generation to the actual electrical loads, or customers. Should transmission access to less expensive generation not be available, then more expensive power would have to be purchased. This is analogous to finding a great price on ice cream across town on a hot summer day but being unable to purchase a ticket on the bus to get it back home in time to avoid melting. In this case, one would be forced to purchase ice cream closer to home at a higher price. If transmission service is too expensive, it may force you to purchase more expensive power.

Today, the for profit electric utilities or often referred to as the investor-owned utilities (IOU) own approximately 77% of all the transmission in the United States, the Power Marketing Agencies (PMA) such as the Bonneville Power Administration (BPA) and the Western Area Power Administration (WAPA) own 12%, the Rural Electric Cooperatives own 6% and the remaining 5% is owned by various municipal and state power entities. Although under current Federal Energy Regulatory Commission (FERC) rules, owners of transmission must make transmission capacity available to wholesale users at a cost no greater than the owner would charge themselves; those who own transmission have a distinct advantage in the wholesale power market. Owners of transmission have preference over others in that they get to use this preference to serve their native electric loads or customers first and should there be any transmission capacity left it can be sold for use to others. Should there be a shortage of transmission capacity; the requester can pay the transmission owner to upgrade the transmission line to make more needed capacity.

Because the production of electric generation and electric transmission has been recently deregulated, the transmission system in the United States and the Pacific Northwest is being utilized in a way differently than it was originally designed. Originally, the system was designed to transmit power generated only by utility type entities. However, today non-utility entities such as IPPs and Power Marketers utilize transmission capacity which would have been used by the utilities themselves. Needless to say, transmission construction has not kept pace with new generation development. Given this fact, transmission should be given a high priority concern for consideration of future power supply options—that is, to build locally or buy outside the area. There is much discussion and debate within the utility industry today about how to best handle the aforementioned transmission capacity shortage. One proposed option surrounds Standard Market Design (SMD) and associated “congestion costs”. This proposal suggests that at specific times and places of transmission congestion there should be higher prices charged and in so doing, provide an incentive for investment in transmission in that specific area. The debate is on-going in this regard.



Pacific NW Transmission Lines by Ownership



## Power Supply Options

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Given the geographic location of the SRR in northwestern most corner of California, there are many power supply options. The options for “central station” produced power and power management are:

1. Federal Power Marketing Agencies
  - a. Western Area Power Administration (WAPA)
  - b. Bonneville Power Administration (BPA)
  
2. Power Marketing/Management Entities
  - a. Northern California Power Agency (NCPA)
  - b. Pacific Northwest Generating Cooperative (PNGC Power)
  - c. The Energy Authority (TEA)

Although historically smaller not-for-profit electric utilities such as electric cooperatives, public utility districts and municipal electric systems often entered into contracts to purchase surplus wholesale power from larger IOUs nearby, this does not seem to be a viable option in the SSR’s geographic location today. All of the area’s IOUs contacted are short of generation and are actively seeking more. That being so, Portland General Electric (PGE), Pacific Power and Light Company (PP&L) and Pacific Gas and Electric (PG&E) are not seeking entering into contracts with others at this time.

In fact, review of BPA’s “White Book” which forecasts power needs for the Pacific Northwest Region against planned new generation construction and the Northwest Power Planning and Conservation Council’s forecasts show the region being in “load to resource balance” only if most of the planned IPP projects are finished and come on line during the time periods planned. If not or if the IPPs arrange to send their generated power outside the region into markets they deem to be more “lucrative”, then the region could suffer significant shortages. Additionally, should the all important Columbia River System suffer from poor snow pack and associated runoff for consecutive years/seasons the regional power generation adequacy becomes even more precarious.

Northwest Region Requirements and Resources

**Northwest Region -  
Requirements and Resources -**

Annual Energy (MWa)	<u>2007-08</u>	<u>2008-09</u>	<u>2009-10</u>	<u>2010-11</u>	<u>2011-12</u>
<b>Requirements</b>					
Load	21,371	21,831	22,141	22,444	22,711
Exports	828	773	866	827	773
<b>Total</b>	<b>22,198</b>	<b>22,604</b>	<b>23,007</b>	<b>23,271</b>	<b>23,484</b>
<b>Resources</b>					
Hydro	11,480	11,478	11,496	11,487	11,486
Small Thermal & Miscellaneous	24	24	24	24	24
Combustion Turbines	1,516	1,526	1,518	1,535	1,496
Renewables	802	868	872	871	862
Cogeneration	1,151	1,148	1,152	1,150	978
Imports	1,684	1,525	1,218	1,016	719
Large Thermal	4,523	4,329	4,404	4,397	4,562
<b>Total</b>	<b>21,181</b>	<b>20,899</b>	<b>20,684</b>	<b>20,480</b>	<b>20,127</b>
<b>Surplus (Deficit)</b>	<b>(1,018)</b>	<b>(1,705)</b>	<b>(2,323)</b>	<b>(2,791)</b>	<b>(3,357)</b>
<b>Potentially Available Resources</b>					
Independent Power Producer Projects	3,086	3,086	3,086	3,086	3,086
Hydro Generation (70 year average)	4,181	4,179	4,160	4,170	4,171

Source: BPA

## Northwest Region

### Requirements and Resources -

Annual Energy (MWa)	<u>2012-13</u>	<u>2013-14</u>	<u>2014-15</u>	<u>2015-16</u>	<u>2016-17</u>
<b>Requirements</b>					
Load	23,049	23,348	23,655	23,972	24,197
Exports	735	722	674	618	555
<b>Total</b>	<b>23,784</b>	<b>24,070</b>	<b>24,329</b>	<b>24,590</b>	<b>24,752</b>
<b>Resources</b>					
Hydro	11,484	11,483	11,481	11,481	11,481
Small Thermal & Miscellaneous	24	24	25	25	25
Combustion Turbines	1,516	1,509	1,518	1,503	1,516
Renewables	855	856	846	845	845
Cogeneration	831	743	745	745	745
Imports	719	722	722	726	581
Large Thermal	4,374	4,617	4,494	4,560	4,494
<b>Total</b>	<b>19,803</b>	<b>19,953</b>	<b>19,831</b>	<b>19,884</b>	<b>19,686</b>
<b>Surplus (Deficit)</b>	<b>(3,981)</b>	<b>(4,117)</b>	<b>(4,498)</b>	<b>(4,706)</b>	<b>(5,066)</b>
<b>Potentially Available Resources</b>					
Independent Power Producer Projects	3,086	3,086	3,086	3,086	3,086
Hydro Generation (70 year average)	4,172	4,174	4,175	4,176	4,176

Source: BPA

## **Federal Power Marketing Administrations**

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The U.S. Federal power marketing program began in the early 1900s when power produced at Federal water projects in excess of project needs was sold in order to repay the Government's investment in the projects. Power Marketing Administrations market this power in such a manner as to encourage the most widespread use and at the lowest rates to users consistent with sound business principles.

Each of the four power marketing administrations (Bonneville Power Administration, Southeastern Power Administration, Southwestern Power Administration and Western Area Power Administration) is a distinct and self-contained entity within the Department of Energy (DOE), much like a wholly owned subsidiary of a corporation.

### *Western Area Power Administration*

Western Area Power Administration (WAPA) markets and delivers reliable, cost-based hydroelectric power and related services within a 15-state region of the central and western U.S. WAPA's role is to market and transmit electricity from multi-use water projects. Its transmission system carries electricity from 55 hydroelectric plants operated by the Bureau of Reclamation, U.S. Army Corps of Engineers and the International Boundary and Water Commission. Collectively, these plants have a capacity of 10,600 megawatts. WAPA and its energy-producing partners are separately managed and financed. In addition, each water project maintains a separate financial system and records.

Currently, the geographical location of the SRR falls within the area of responsibility of the WAPA Sierra-Nevada Region's Sacramento, California office in Folsom. According to Jeannie Haas, WAPA Account Executive (AE) and the approved WAPA 2004 Marketing Plan, the SRR qualifies for an allocation of Central Valley Project (CVP).

The CVP power facilities include 11 power plants with a maximum operating capability of about 2,044 megawatts (MW), and an estimated average annual generation of 4.6 million megawatt hours (MWh). To receive an allocation of this low cost power, the SRR would need to make a request of WAPA for an allocation and dedicate it to load within the SRR which is no less than 500kw or ½ MW. WAPA allocates 100% of the CVP output per Marketing Plan so as of the result of the 2004 Marketing Plan the output is already fully allocated. Nonetheless, a request filed today would result in some level and/or amount of allocated power for the SRR in the new 2015 Marketing Plan period. Additionally, eligible Native American entities will receive greater consideration for an allocation of up to 65% of their peak load in the calendar year prior to the Call for Applications.

Fortunately, the SRR has two options available to receive delivery of the aforementioned low-cost WAPA CVP hydro-power. The first and most common method would be for the SRR to establish their own electric utility along with ownership of hard utility assets such as power poles, wires and transformers. This approach would require the acquisition and purchase of existing electric distribution facilities from the current IOU provider Pacific Power and Light Company (PP&L). Of course, this approach would entail discussions and eventual negotiations with PP&L over their willingness to sell

electric distribution facilities serving the SRR. These discussions could span months and/or years given PP&L's incentive to divest themselves of the delivery assets.

In the establishment of the Umpqua Indian Utility Cooperative (UIUC) in Canyonville, Oregon in 2001 for the Cow Creek Band of Umpqua Tribe of Indians PP&L was the prior existing power provider. In this case, PP&L informed the Cow Creek Band that it had an internal policy that none of their facilities were for sale. That being so, it was the Tribe's belief that negotiating the purchase of the serving distribution facilities was not possible. They believed a legal taking, or condemnation was the only option. However, as it turned out, PP&L was cooperative and all activities were amicable. A PP&L representative was later interviewed for a news article after the new utility became operational. This company spokesperson stated that they understood the Tribe's right to sovereignty, and conversely, the tribe understood their responsibility to their customers and shareholders. Given this recent example with PP&L and the establishment of a Tribal Utility one could assume a similar approach in the establishment of a SRR Tribal Utility.

The second option is to receive the benefit of a WAPA CVP allocation through the newly established "bill crediting" program. In an effort to bring more allocation benefits to economically disadvantaged Native American communities, WAPA has waived the requirement that Tribes own "hard utility assets". This means that Tribes no longer need to own a utility (poles, wires, transformers, etc.) to receive the benefits from a WAPA allocation. "Not requiring the tribes for form utilities has several benefits. Forming a utility is a lengthy and expensive process," according to Bob Fullerton, a WAPA power marketing advisor. "Waiving the utility formation requirement allows the tribes to enjoy the economic benefits of cost-based hydropower without the costs and time delays of utility formation." He went on to say that many tribes already own their own utilities.

Under the bill crediting program WAPA works out a crediting and pooling arrangement with existing serving utilities in the region, who then pass on the benefit of receiving the lower cost Federal hydropower directly to the Tribes. Prior to the bill crediting program 31 Tribes received the benefits of a WAPA allocation; today the number has risen to 91. In the Sierra-Nevada Region of WAPA, those receiving benefits under this program in California are:

1. Coyote Valley Tribe of Pomo Indians
2. Redding Rancheria
3. Susanville Indian Rancheria
4. Table Mountain Rancheria

There is little question that the benefits of a WAPA allocation of power to the SRR are possible. And, of course, there are options for receiving these benefits, either receiving delivery of these benefits to a hard asset Tribal utility or through the existing bill crediting program. The pros and cons of such a decision must be examined carefully taking into consideration both short and longer term goals. Additionally, a determination must eventually be made relative to receiving delivery of power/benefits from either WAPA or BPA. Fortunately for the SRR, given the goals and associated strategies to be deployed, decisions will need to be made early on to either receive delivery of an allocation/benefits from either WAPA or BPA or develop strategies to receive benefits from both of them.

## *Bonneville Power Administration*

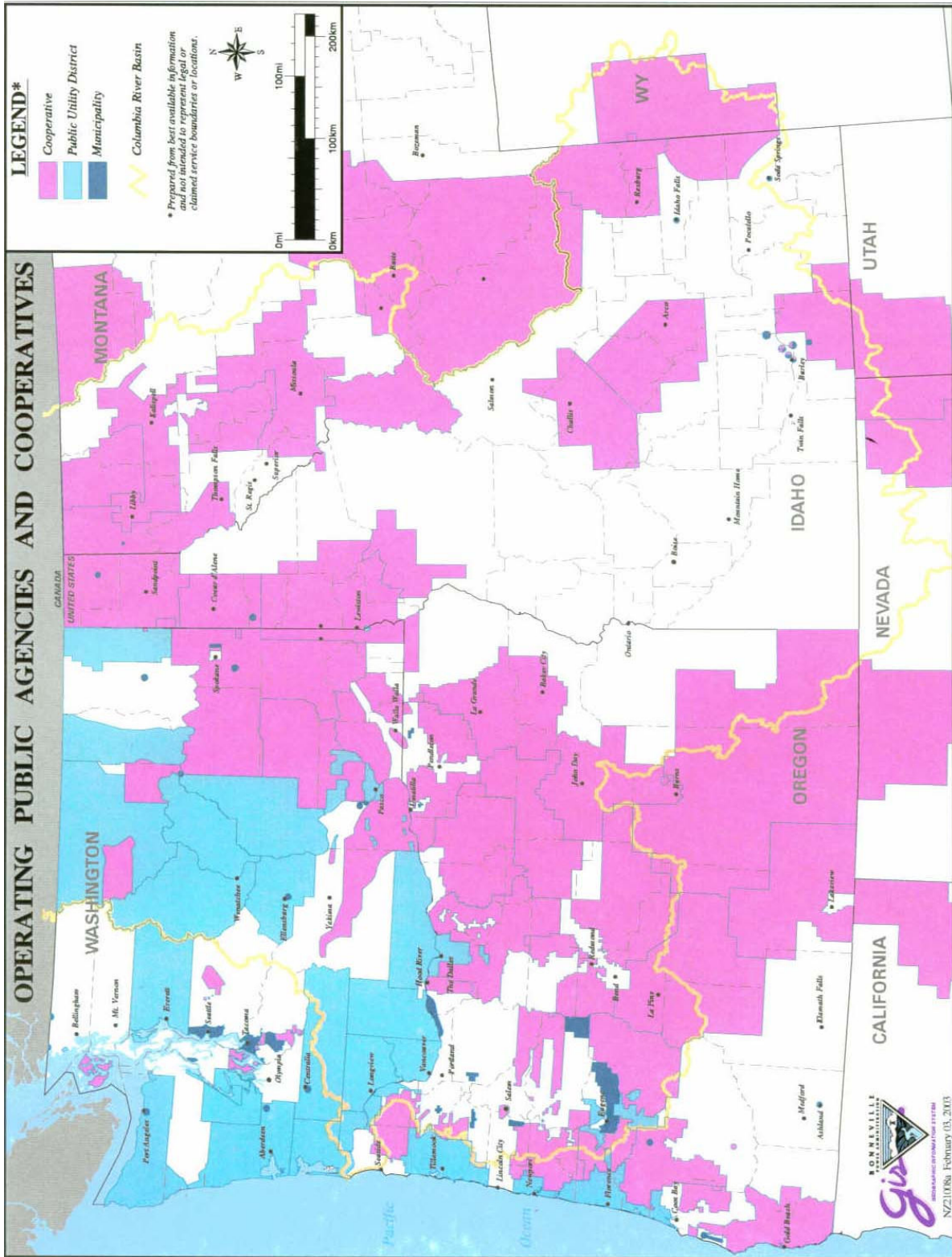


The Bonneville Power Administration (BPA) is a federal agency headquartered in Portland, Oregon, that markets wholesale electricity and transmission to the Pacific Northwest's public and private utilities as well as to some large industries. BPA provides about half the electricity used in the Northwest and operates over three-fourths of the region's high-voltage transmission. While BPA is part of the Department of Energy (DOE), it is not tax supported through government appropriations. Instead, BPA recovers all of its costs through sales of electricity and transmission and repays the U.S. Treasury in full with interest for any money it borrows.

Currently, although the SRR geographically lies within the Sierra Nevada Region of WAPA's service area, there are opportunities to qualify a SRR Tribal utility as a customer of BPA with rights to an allocation of low cost wholesale power. However, at this time, BPA does not administer a bill crediting program like WAPA to ease the transfer of low cost power allocation benefits to Tribal utilities. BPA only delivers to those utilities meeting certain "standards for service". BPA's determination of a customer's eligibility to purchase Federal power is made in an overall review to determine if the customer is in compliance with the BPA Administrator's standard for service. The standards for service are summarized as follows. The purchaser/customer/utility must:

1. - be legally formed in accordance with local, state, Federal or tribal laws;
2. - own a distribution system and be ready, willing and able to take power from BPA within a reasonable period of time;
3. - have a general utility responsibility within the service area;
4. - have the financial ability to pay BPA for the Federal power it purchases;
5. - have adequate utility operations and structure; and
6. - be able to purchase power in wholesale amounts.

# Operating Public Agencies and Cooperatives







## **Legal Formation**

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This standard is applicable to potential new preference customers and to new private utilities selling to the general public. It does not apply to Federal agencies. As applied to an entity seeking to purchase Federal power as a preference customer, it requires an applicant to demonstrate that all required steps under applicable local, state, Federal, or tribal laws have been taken to authorize its formation as a public body or cooperative. Tribal utilities seeking to purchase must be formed by Indian tribes which are federally recognized. As applied to investor owned utilities, this standard requires that such entities are legally incorporated as utilities, authorized to sell and distribute electric power at retail, and are subject to state utility regulation. This standard ensures that the applicant is in the public business of buying and distributing, at retail, power to be purchased from BPA, or is in the process of going into such a business. All applicants must provide copies of filings of certificates and approvals from designated officials, such as by-laws and articles of incorporation, regulatory approvals as required, and information on whether public elections were required and held.

## **Distribution Ownership**

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This standard requires purchasers, including Federal agencies, to own the distribution facilities necessary and used to deliver Federal power to the applicant's retail consumers. Such standard assures that BPA sells power consistent with the legal requirement that Federal power be sold to customers engaged in the public business of buying and distributing power through distribution facilities owned by the customer. The requirement to own, operate, maintain, and control the costs of distribution is viewed as a means to assure that the benefits of low cost Federal power reach the citizens of the Pacific Northwest. Under certain circumstances the BPA administrator may determine it is appropriate to provide an exception to the standard to own all the necessary distribution facilities located on tribal reservations. The Administrator will consider, on a case-by-case basis, issues related to the ownership standard regarding difficulties that tribes may face in pursuing the acquisition of all the distribution facilities on tribal reservations.

For newly forming public body and cooperative utilities, BPA must give the applicant a reasonable opportunity to achieve ownership, including time needed to finance the acquisition or construction of the necessary distribution. In general, public bodies have the power of eminent domain which allows them to acquire the distribution facilities of another utility through condemnation. In general, cooperatives have been able to construct or purchase their own systems through financing obtained from loans made by the Federal Rural Electric Administration (predecessor to the Rural Utility Service) or by other sources of financing.

## **General Utility Responsibility**

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This standard requires that a purchaser serving retail consumer load have a "utility responsibility," i.e., an obligation to serve. This means that any retail consumer may request and obtain service from the potential BPA customer, limited only by service area or geographic franchise allocation restrictions. Such a standard assures that Federal power will be sold by the applicant in a non-discriminatory manner for the benefit of the general public and particularly of domestic and rural consumers. An applicant must

have obtained authorization to serve loads or areas prior to receiving Federal power from BPA for service to such loads or areas. Any legal action that challenges such service must be resolved by final order before BPA begins service. This standard is not applicable to Federal agencies.

## **Financial Ability to Pay**

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This standard requires that an applicant have the authority to collect money for the services it renders to its retail consumers-the ability to bill-and the applicant's authority to sue and be sued. Such a standard assures BPA that the purchaser is able to pay for the Federal power. In applying this standard, BPA reviews the applicant's organizational structure to see if there is administrative staff that performs a billing and collection function. BPA will also examine, particularly in the case of a municipal or tribal applicant, whether the applicant has the authority to segregate utility funds from a general fund, if one exists. In applying this standard to Federal agencies, BPA will review an agency's appropriations and authorities to purchase power.

## **Operations and Structure**

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This standard requires that a purchaser have the ability through the operational and organizational structure to perform utility functions such as metering, billing, operation and maintenance on utility facilities. Such a standard provides BPA reasonable assurance that the applicant has the ability to fulfill responsibilities and duties under its power sales contract with BPA.

## **Wholesale Amounts**

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This standard requires that Federal power be purchased in wholesale amounts. BPA is directed to sell power at "wholesale" and has generally required that customers purchase Federal power in wholesale amounts of one megawatt or more.

## **Establish/Define the SRR Tribal Utility is a Pacific Northwest Load**

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BPA is only able to serve those utilities and loads which reside within their "marketing area" which is defined as the Pacific Northwest or Pacific Northwest region. This is more precisely defined by the Regional Preference Act as:

(A) the area consisting of the States of Oregon, Washington, and Idaho, the portion of the State of Montana west of the Continental Divide, and such portions of the States of Nevada, Utah, and Wyoming as are within the Columbia River drainage basin; and

(B) any contiguous areas, not in excess of seventy-five air miles from the area referred to in subparagraph (A), which are a part of the service area of a rural electric cooperative customer served by the Administrator on December 5, 1980, which has a distribution system from which it serves both within and without such region.

Please note there is no mention of the State of California. However, this definition is written in such a way that existing cooperatives within Oregon can serve electric loads across the border 75 miles into California; this is how the Surprise Valley Rural Electric Cooperative serves California consumers with BPA wholesale power. Analogously, the CCEC could serve electric loads from the California border all the way through Crescent City and down to the Klamath, California area should those loads become part of CCEC or become part of CCEC with arrangements to later be spun off and divested to become a stand alone SRR Tribal utility.

Yet, other arrangements could be pursued to establish a SRR Tribal utility in Oregon just at the California border which then could stretch across the border in service provision and thus qualify for a preference allocation of BPA wholesale power. It is not clear at this writing, because it would require further legal research, whether or not SRR Tribal utility loads located in the Whaleshead area of Curry County, Oregon, some distance from the border, could be established to qualify for the aforementioned treatment. Needless to say, considerably more legal research is needed and strategy developed before a clear and rational approach could be deployed.

It is evident from the aforementioned “standards for service” that for a SRR Tribal utility to receive the benefits of an allocation of low cost BPA wholesale power, the SRR Tribal utility would be required to:

1. meet the BPA “standards for service” by acquiring the existing PP&L distribution - facilities or; -
2. convince the BPA Administrator that there is ample justification to waive the “ownership” standard to allow either a lease of facilities from PP&L to the SRR Tribal utility to enable power delivery or allow a “billing credit” arrangement similar to WAPA’s program where the benefits of lower cost BPA power is netted from the electric bills of existing Tribal electric loads resulting in a rate decrease and also;
3. establish that the SRR Tribal utility provides electric service to tribal electric loads on lands in “trust” in Oregon, adjacent to or contiguous to tribal electric loads on tribal lands in California within the generally recognized 75 mile limit from the border or in agreement with Coos Curry Electric Cooperative (CCEC) have CCEC span the border into California and serve the SRR and/or tribal loads with an agreement to transfer these loads, distribution facilities and preference allocation to the SRR Tribal utility at some certain in the future.

It is certain that there are numerous steps and strategic considerations relative to the establishment of a SRR Tribal utility and qualifying for an allocation of low cost BPA preference power. The eventual strategy chosen and the timing of its deployment should be contingent upon both the short and long-term goals of the SRR. Additionally, timing consideration must be given to the most recent BPA “Long-Term Regional Dialogue Final Policy” which dictates who, and how and how much and just when existing and new customers will receive their preference allocations from BPA. By October of 2008, BPA is expecting to be fully allocated and have contracts with every entity which expects to receive power from BPA over the next 20 years beginning with the 2011 fiscal year. Given this, it is important to understand many of the important elements of this policy.

## **BPA's Long-Term Regional Dialogue Final Policy & Record of Decision**

Over the past several years the Pacific Northwest Region's BPA stakeholders, in a multitude of forums, have been debating how BPA will market its wholesale power post-2011. Additionally, there has been expressed concern that the way BPA markets power in the future must ensure that key regional and national goals are met. There is no question that the federal system's clean, renewable hydropower has become increasingly valuable as the nation focuses on energy independence and climate change.

The timing of all of this is crucial if BPA's customers are going to have enough time to make choices about securing an adequate, long-term power supply. Only four years remain before current wholesale power sales contracts expire. It is BPA's goal to have new 20-year contracts signed by December 2008. The proposed 20-year contract time span will give long-term certainty necessary for the major infrastructure investments the region needs.

The Policy includes a new tiered rate approach that provides each public utility customer with a High Water Mark (HWM), which will define its right to buy power at a Tier 1 rate. This Tier 1 rate will be based on the cost of the existing federal system with little additional augmentation of non-federal supply. Should preference customers opt to buy more power from BPA beyond their HWM, that power will be sold at a Tier 2 rate set to recover BPA's costs of obtaining additional power sources to serve the load.

However, BPA customers may opt for solutions other than Tier 2 for load growth beyond the less expensive Tier 1. Customers do have the option to acquire their own resources or purchase power on the open market. This new Policy gives customers more choices as to how to supply their new load growth.

The following is a brief summary of the Regional Dialogue Policy:

*New 20-year contracts and tier rates:* BPA will develop new 20-year power sales contracts along with a long-term Tiered Rates Methodology. Through the contracts and rate methodology, each public utility will get a High Water Mark (HWM) which defines its right to purchase power at a Tier 1 rate based on the cost of BPA's existing system. Power above the HWM must be purchased from new nonfederal resources or from BPA at a higher rate reflecting BPA's full cost of acquiring additional power. BPA will not subsidize its Tier 2 power rate with its existing system, but will otherwise make its best efforts to provide low-cost Tier 2 options for customers who choose not to secure their own resources to meet load growth.

*New Publics and Tribal utilities:* BPA will make augmentation purchases, if necessary, to supply up to 250 average megawatts at the Tier 1 rate to new publics, including new and existing public body tribal utilities. This will cover the reasonably foreseeable needs to serve new public utilities without reducing the availability. Additionally, the policy commits BPA to reserve 40 average megawatts of Tier 1 rate power (out of the 250 average megawatts total available for new publics) for the expansion of new and existing tribal utilities.

*Augmentation:* BPA will purchase power to augment the existing system by up to 300 average megawatts, if needed, to meet public utility loads at the Tier 1 rate. This is approximately a 4% increment to the existing system and is in addition to any power augmentation for new publics.

*Product choices:* BPA will offer customers three product choices: Load-Following, Block and Slice. Only the Load-Following product will include services to follow the actual loads a customer has.

*Slice:* The Policy provides for a modest increase in the amount of power sold under the Slice product from the existing 22.6% to as much as 25% of the power available from the Federal Base System. The Slice product will be refined to include modest changes to within-hour flexibility rights and to more accurately and fairly share operational flexibility and limitations.

*Cost control:* BPA will institute a regional cost review to give customers and other stakeholder's plentiful and meaningful opportunities to provide input to BPA on costs.

*Dispute resolution:* The Policy responds to customer requests for robust dispute resolution mechanisms that have greater reliance on third-party arbitration for disagreements than occurs presently. It lays out guidelines for dispute resolution, while stressing that final determination of the appropriate mechanism for particular issues must be done in conjunction with development of the power sales contracts.

*Conservation and renewable resources:* Under the policy, BPA commits to work in partnership with its public utility customers to achieve public power's share of regionally cost-effective conservation and renewables. In future rate cases, BPA will propose to recover conservation and renewables facilitation costs in the Tier 1 rate.

*Resource adequacy:* The Policy stipulates that BPA customers will be required to provide their load and resource data and resource development plans necessary to track implementation of the voluntary resource adequacy standards adopted by the Northwest Power and Conservation Council.

*Low Density Discount (LDD) and Irrigation Rate Mitigation (IRM):* This Policy commits BPA to propose stable and predictable LDD and IRM programs in future rate proceedings and to propose an LDD approach that avoids biasing customers' choices between buying power at a Tier 2 rate from BPA or power from nonfederal resources.

*Transfer Service:* The Policy addresses several Transfer Service issues that were identified in the Agreement Regarding Transfer Service signaled in April 2005. These issues include supplemental guidelines to the Transmission Services' direct assignment guidelines, quality of service, administrative roles and responsibilities, ancillary services, transfer of nonfederal power, service to new customers and annexations.

Needless to say, BPA has many details yet to be worked out relative to the aforementioned Policy. New contracts must be negotiated and drafted, released for public comment and, eventually, executed. BPA must also make net requirements determinations for its customers.

BPA must also complete development of specific products and services. While the Policy establishes three major power products (Load Following, Slice and Block), the detailed structure of those products is being worked out. BPA also must work out details in such areas as irrigation mitigation and low-density discounts.

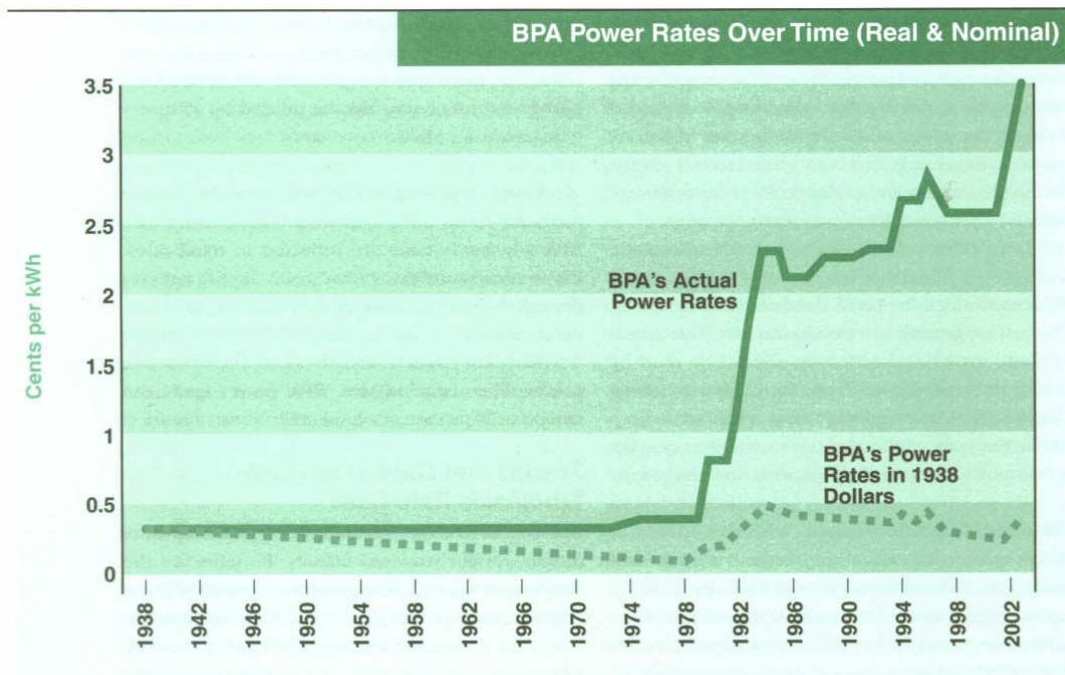
There will be several follow-on processes to work out these implementation details. BPA's goal is to sign 20-year power sales contracts in late 2008 in time for regional utilities to arrange how they will receive power beyond what they have requested from BPA. Fortunately, BPA has established a Tribal Affairs Team to assist tribes with the multitude of the aforementioned issues.

Through its Tribal Affairs staff and business units, BPA is dedicated to providing the following services to the region's tribes.

1. Develop and maintain strong government-to-government relationships and provide - consultation and technical assistance to tribes. -
2. Proactively anticipate the tribes' need for information and be responsive to tribal - requests for information on BPA initiatives, such as power products and services, utility formation, - wholesale power rates, renewable resources development, transmission facility development, - energy efficiency programs and right-of-way policies. -
3. Provide information to tribes to help them understand BPA perspectives on power, - transmission and environment and fish and wildlife issues being discussed in the region. -
4. Fully consider the interest of tribes when establishing BPA policies that impact them such as river operations, transmission system maintenance and development, environment, and fish and wildlife programs. Engage the affected tribes in two-way dialogue about potential policy and program changes.

BPA's Tribal Affairs Team point out that owning and operating utilities allows tribes to work in their best interest and that of tribal members. A tribal utility can work for the sustainable development of the tribe through policies set and accepted by tribal members. Access to cost-based power from federal power marketing administrations in most cases will lower tribal members' utility bills. Towards that end, BPA has assigned Shannon Greene as the SRR contact for SSR's investigation into becoming a preference customer of BPA and associated tribal utility formation. She can be contacted at 206-220-6775 or [skgreen@bpa.gov](mailto:skgreen@bpa.gov).

## BPA Rates Over Time



The rate shocks of the 1970s and 1990s are plain on this chart of BPA's historical rates. Note that until 2002, BPA's rates included both power and delivery (transmission). Now customers pay a separate rate for transmission.

## Power Marketing/Management Entities

Given the geographic location of the SRR, three power marketing/management entities are listed in this investigation for consideration. Such as any other utility today, a newly established SRR Tribal utility would have the need to procure more power for electrical load growth on the system and also have the need to schedule and manage this power. The Northern California Power Agency (NCPA), Pacific Northwest Generating Cooperative (PNGC) and The Energy Authority (TEA) all work with utility clients in the geographic area of the SRR and work exclusively with not-for-profit, public utilities. Both NCPA and PNGC are structured as Joint Operating Entities whereas TEA is not.

All of these entities provide the advantage of sharing costs or "economies of scale", sharing operating gains and losses and sharing the diversification of risk. Outside of the regions two Federal Power Marketing Agencies BPA and WAPA these power marketing/management entities are the prime potential providers of services for the SRR.



## NCPA

NCPA is located in Roseville, California and is a state of California joint powers agency that provides support for the electric utility operations of 17 member communities and districts in Northern and Central California. NCPA own and operate several power plants that together comprise a 96% emission-free generation portfolio. NCPA was founded in 1986 as a forum through which community-owned utilities could prevent costly market abuses employed by private utilities at that time, and to make investments to ensure an affordable, reliable and clean future energy supply for the electric ratepayers they serve. Currently, NCPA manages 1800 MW of electric load.

Membership is open to municipalities, rural electric cooperatives, irrigation districts and other publicly owned entities interested in the purchase, aggregation, scheduling and management of electrical energy. For nearly four decades, NCPA has successfully provided scale and skill economies devoted to the purchase, generation, transmission, pooling and conservation of electrical energy and capacity for its members. With the onset of electric utility restructuring, the Agency has become a primary supplier of power scheduling and interchange management services to power marketers and public agencies.

NCPA operates through four Business Units: Finance and Administration Services, Generation Services, Legislative and Regulatory, and Power Management. NCPA members and associate members individually elect participation in Agency activities according to their particular needs. According to Don Dame, NCPA Vice President of Business Expansion, NCPA would need to investigate the details involved in serving electrical loads in the SRR area prior to committing to provide service.

NCPA members are:

City of Redding	Plumas-Sierra Cooperative	B.A.R.T.
City of Ukiah	Truckee Donner PUD	Port of Oakland
City of Healdsburg	City of Lompoc	City of Palo Alto
City of Biggs	City of Roseville	Placer County Water Agency
City of Gridley	City of Alameda	City of Lodi
City of Santa Clara	Lassen MUD	Turlock Irrigation District

## PNGC

PNGC Power is a cooperatively owned power services business providing economic and strategic value to 15 cooperative member-owner utilities serving customers in seven western states (Oregon, Washington, Idaho, Montana, Utah, Nevada and Wyoming). For over a decade, PNGC Power has consistently offered member-owners a competitive advantage despite significant weather and market-related challenges. Having the advantage of a very experienced staff and also having advanced analytic

tools, technology and policy leadership, PNGC Power is able to minimize risk and maximize benefits for member cooperatives.

PNGC Power is backed by \$738 million in assets of its member-owners. By aggregating together as one entity, these cooperative utilities have more options than any one of them could have alone. This results in more purchasing leverage, technical capabilities, financial strength, risk management capability and control. This gives member utilities the collective clout to offer customers reliable, low-cost power options at stable prices. Currently PNGC manages a portfolio of approximately 450 MW.

PNGC’s members are:

Blachly-Lane Electric Cooperative, Oregon	Central Electric Cooperative, Oregon
Clearwater Power Company, Idaho	Consumers Power Inc., Oregon
Coos Curry Electric Cooperative, Oregon	Douglas Electric Cooperative, Oregon
Fall River Rural Electric Cooperative, Idaho	Lane Electric Cooperative, Oregon
Lost River Electric Cooperative, Idaho	Northern Lights Inc., Idaho
Okanogan County Electric Cooperative Inc., Idaho	Raft River Rural Electric Cooperative, Idaho
Salmon River Electric Cooperative, Idaho	Umatilla Electric Cooperative, Oregon
West Oregon Electric Cooperative Inc., Oregon	

### TEA

The Energy Authority (TEA) is one of the nation’s leaders in Public Power energy trading and risk management. TEA is wholly-owned and directed by their Public Power members and partners who participate in the organization’s decision making. Currently 40 Public Power entities across the nation do business with TEA, representing more than 25, 000 MW of combined generation assets and fuel types. TEA provides a wide array of products and services designed to manage risk and enhance energy asset efficiencies for utilities across the nation. TEA offers a variety of resource management services to suit the needs of utilities—from bilateral power trading, to risk analysis and management, to full credit and contract support. Members of TEA have access to the dedicated resources, sophisticated systems, and highly skilled staff necessary to maximize the value of supply contracts and generation assets. In addition, TEA’s broad market reach gives members the advantage of national trading and price discovery. According to Jim Sanders, General Manger of PUD No. 1 of Benton County, Washington, “TEA’s trading and power supply management operations enable it to bring a practical, real-world perspective to its advisory services that many traditional consulting firms often times lack. TEA also goes beyond simply producing a study report and is there to help us implement its recommendations.”

TEA serves: -

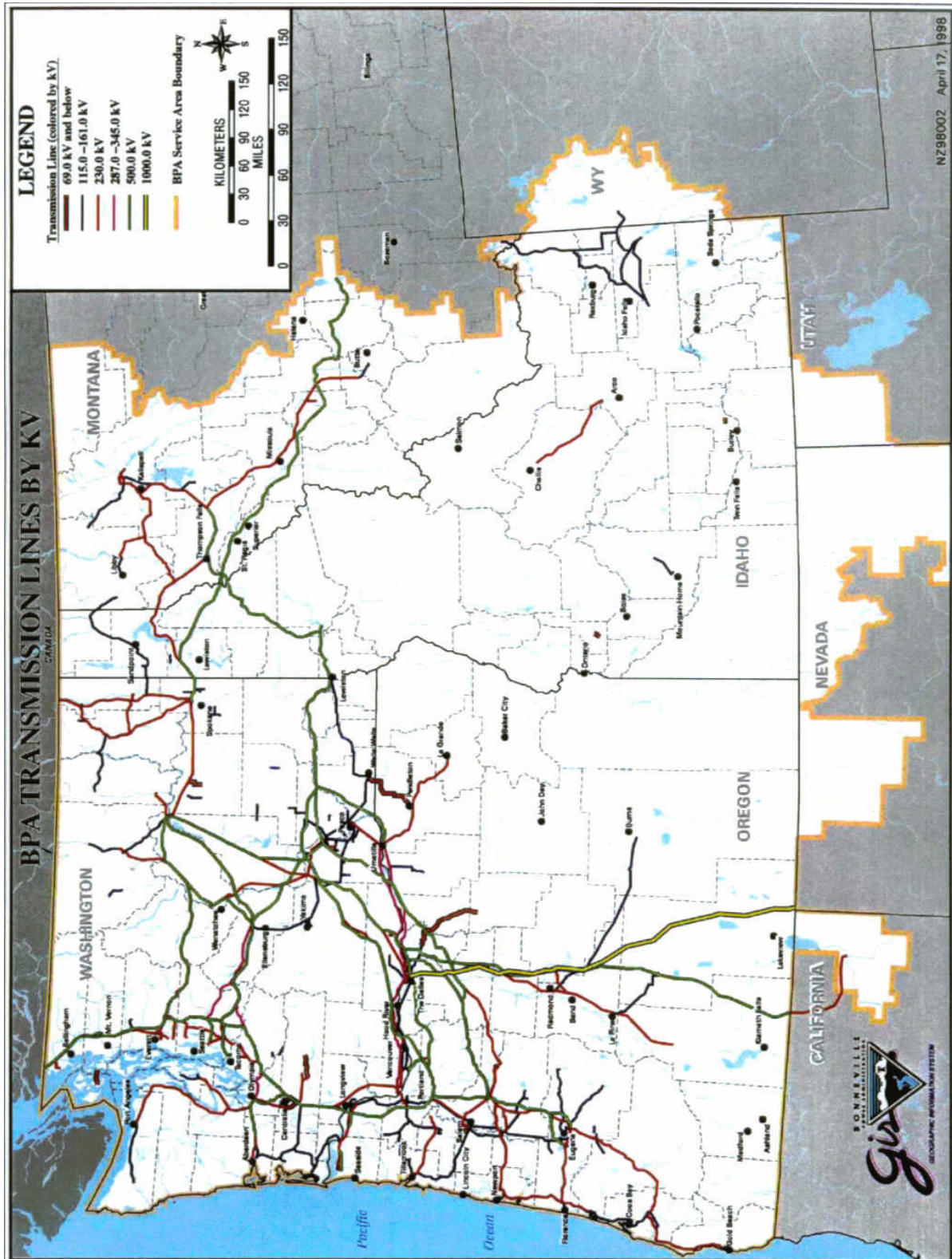
American Municipal Power – Ohio	Benton Public Utility District
City of Fulton, MO	City Utilities of Springfield, MO
Clallam Public Utility District	Clatskanie People’s Utility District
Columbia, MO, Water & Light	Cowlitz Public Utility District
CPA Energy	Emerald People’s Utility District
Energy Northwest	Flathead Electric Cooperative
Florida Municipal Power Agency Gainesville Regional Utilities	Franklin Public Utility District Grays Harbor Public Utility District
JEA	Klickitat Public Utilities District
Lafayette Utilities System	Lakeland Electric
Lewis Public Utility District	Louisiana Energy and Power Authority
Mason Public Utility District #3	Massachusetts Municipal Wholesale Electric Company
Merced Irrigation District, CA	Municipal Electric Authority of Georgia
Nebraska Public Power District	Okanogan Public Utility District
Pend Oreille, Public Utility District	Piedmont Municipal Power Agency
Rochester Public Utilities	Santee Cooper
Port of Seattle, Seattle-Tacoma International Airport	Snohomish Public Utility District
Southern Minnesota Municipal Power Agency	Springfield, IL, City Water & Power
University of Missouri	Wisconsin Public Power, Inc.

## Transmission Paths

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No investigation into power supply would be complete without a complete discussion about transmission and transmission paths. As of the result of FERC Order 888 and numerous subsequent other rulings, those entities owning and operating transmission assets cannot use these assets for unfair market power. This being so, no utility can refuse transmission access to another utility, non-utility generator and power marketer in need of this access. Under these FERC rulings, those owning transmission must make access available to others at a cost no greater than the transmission owner would charge themselves. These charges manifest themselves in the form of "Open Access Transmission Tariffs" which are filed with FERC. Additionally, should there not be sufficient transmission capacity available; the requesting party may opt to purchase the construction of additional capacity. All of the aforementioned is initiated through a formal request to the transmission providing utility. Should the requesting party actually require a physical interconnection, the transmission providing utility will require monies to fund analysis to determine the technical aspects of the proposed transmission. Once this study is completed, the requesting party is informed of the costs which must be paid prior to construction.

BPA Transmission Lines By KV



## *Pacific Power & Light*

Currently, the SRR's power provider, Pacific Power & Light (PP&L), is also the area's transmission provider. The system supplying the SRR is fed from Crescent City. Crescent City is sourced from Grants Pass Substation through three 125 MVA 230 kV to 115 kV transformers rated for 150 MVA at winter peak loading. Two 115 kV transmission lines comprised of 397 ACSR (or larger) conductor follow separate paths to Cave Junction, except for a three mile section at the Cave Junction end. Cave Junction Substation is comprised of a 115 kV ring bus, 115 kV to 69 kV transformer, and a 69 kV connected distribution substation.

Happy Camp substation is normally supplied from Cave Junction at 69 kV. Two 115 kV 397 ACSR lines supply Del Norte Substation in Crescent City, and are closely spaced in a common corridor from about a mile south of O'Brian Substation to Del Norte Substation. Three distribution substations are supplied on one of these lines. This line route passes through very rugged heavily forested terrain with difficult access. Del Norte Substation supplies the Crescent City area 69 kV distribution substations through a pair of 115 kV to 69 kV LTC (load tap changers) transformers.

The Crescent City 69kV system is configured in an open loop, with radial branches supplying Yurok Substation to the south and Smith River and Simonson substations to the north. Simonson substation is being replaced with a new Morrison Creek Substation due to its deteriorated condition. A transmission right-of-way extends from the Simonson Substation site to the Oregon border, but the conductors have been removed. Transmission switched shunt capacitors are located at Grants Pass, Cave Junction, Del Norte Redwood and Belmont Substations. The Grants Pass and Cave Junction areas are summer peaking and summer limited, while the Crescent City system is winter peaking and winter limited.

Southern Oregon/Northwestern California Transmission



Figure 1  
Crescent City District Transmission

Crescent City substation is a distribution substation and out of the scope of this study.

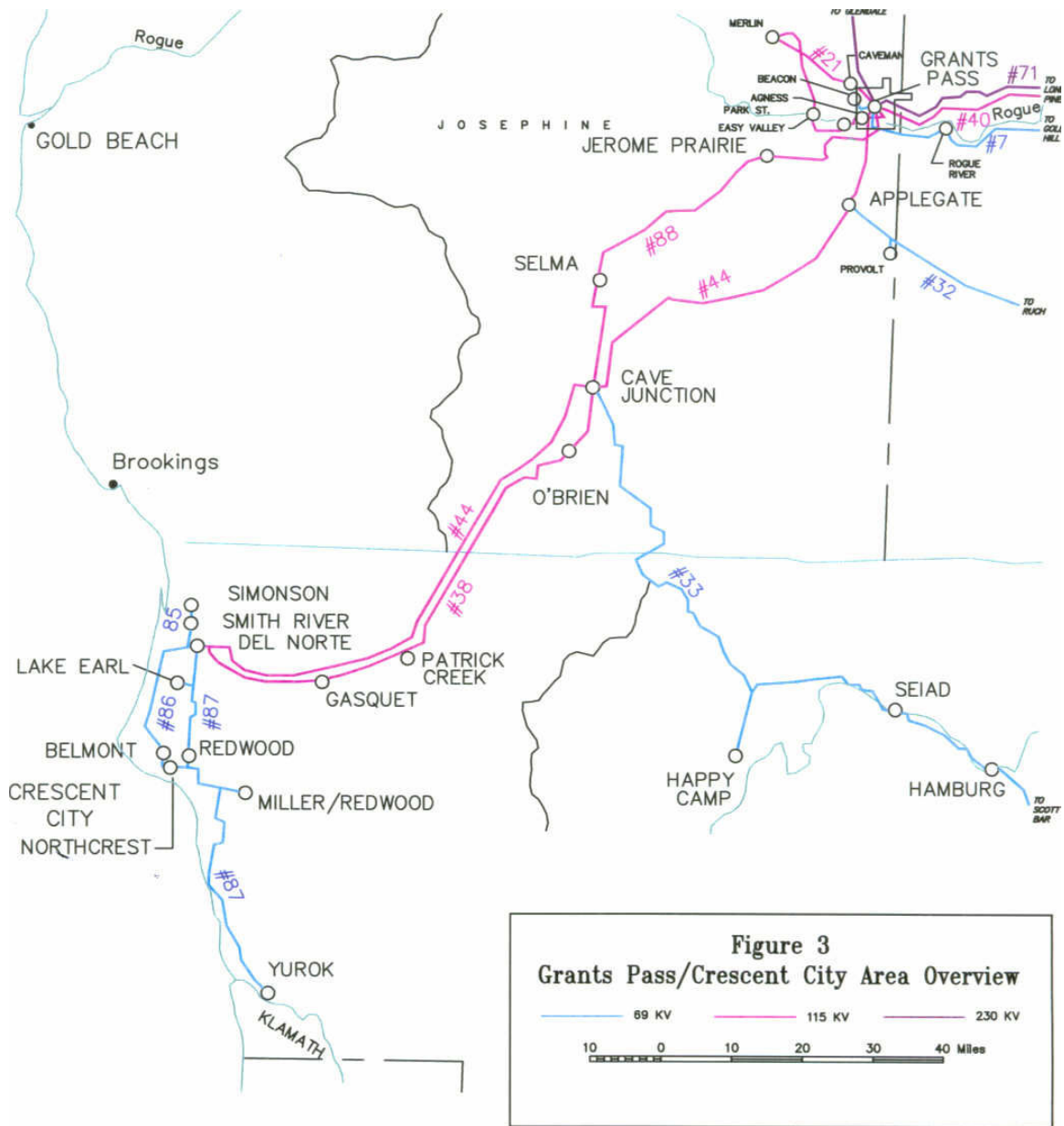
### *BPA/Coos Curry System*

Although the SRR is approximately 6 miles from the Coos Curry Electric Cooperative to the north and not presently interconnected, a discussion of the CCEC system is warranted because of the aforementioned potential for transmission and business interconnection. The southern Oregon Coast load service area spans the Oregon Coast line from Fairview down to Brookings and serves the City of Bandon, Coos Curry Electric Cooperative and Pacific Power & Light's Isthmus and Coquille feeders. The area is served via two 230-kV lines from BPA's Alvey and PP&L's Dixonville substations respectively and a 115-kV line out of BPA in Reedsport. Loads south of Fairview are served by the 230-kV Fairview-Rogue line and the 115-kV Bandon-Rogue line.

The southern Oregon Coast is a winter-peaking area and the weakest portions of the system are the two radial lines going south out of Rogue to Brookings and Harbor on the Coos Curry system. These lines are susceptible to low voltages and voltage collapse. The worst single event for this area is the loss of the BPA Fairview-Rogue 230-kV line. Previous studies suggested there is a possibility in the near future of voltage instability if the Fairview-Rogue event occurs during winter peak load hours.



Local Transmission Schematic



## **Potential Transmission 115 kV Intertie BPA/CCEC/PP&L**

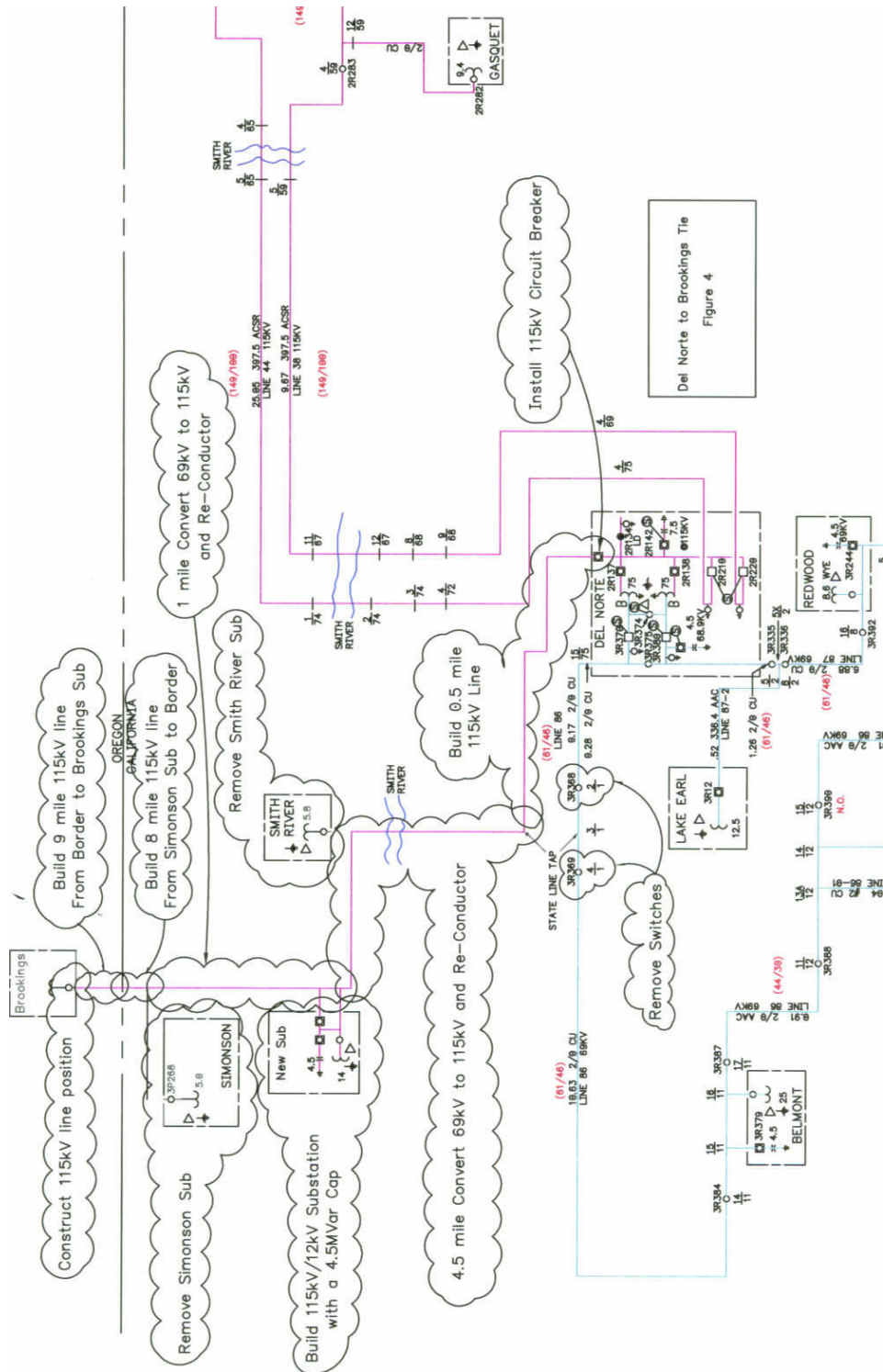
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Because of existing loads and forecasts of increasing loads on the southern end of the CCEC system in Brookings-Harbor, BPA has historically been planning the construction of a third 115 kV transmission line from Bandon to Gold Beach. The timeframe for the project is “load dependant” but is tentatively planned for completion in the 2010-2012 time period. Absent this additional transmission capacity, BPA will not be able to satisfactorily maintain voltage levels on the CCEC system.

Confidential discussions between BPA, CCEC and PP&L have initiated a joint study to research the possibility of connecting CCEC’s 115kV transmission line with PP&L’s transmission line at the Oregon-California border. The initial results of the study indicate the interconnection would, in effect, bring greater benefits to all the stakeholders than the previous plan of constructing a third 115kV transmission line from Bandon to Gold Beach. Additionally, it appears as if between \$30 to \$40 million would be saved with the interconnection alternative and also provide for greater transmission line reliability.

Needless to say, the interconnection alternative is in the initial planning stages and most of the interconnection investigation is confidential. At this writing, the interconnection has become BPA’s preferred alternative opposed to the third 115kV transmission line. Many various sub-studies will be performed and completed to ascertain specific transmission line routing and potential right-of-way costs. This confidential information was made available only to the SRR through former CEO/General Manager Werner G. Buehler.

Proposed Changes for CCEC/PP&L Transmission Interconnect



Del Norte to Brookings Tie  
Figure 4