EXHIBIT NO. KRK-5
DOCKET NO. UE-10____
WITNESS: KARL R. KARZMAR

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

In the Matter of the Petition of **PUGET SOUND ENERGY, INC.** **For a Declaratory Order Regarding the Transfer of Assets to Jefferson County Public Utility District.**	**Docket No. UE-10____**

FOURTH EXHIBIT (NONCONFIDENTIAL) TO THE PREFILED DIRECT TESTIMONY OF
KARL R. KARZMAR
ON BEHALF OF PUGET SOUND ENERGY, INC.

JULY 15, 2010

FEASIBILITY CONSIDERATIONS

FOR THE PROPOSED GOVERNMENT TAKEOVER OF PUGET SOUND ENERGY'S

ELECTRIC UTILITY BUSINESS WITHIN

JEFFERSON COUNTY

PREPARED BY

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photo: PSE's new Chimacum substation in Jefferson County

(Preliminary Assessment)

Date of Report: July 2008

This report is designed to provide the Jefferson County Community with a preliminary assessment of the costs that would be involved to purchase, finance, and operate Puget Sound Energy's electric utility business within the boundaries of Jefferson County.

Qualifications

UtiliPoint International, Inc. (UtiliPoint) was retained by Puget Sound Energy (PSE) to provide an independent preliminary assessment of some of the potential implications of Jefferson County PUD #1 acquiring PSE's existing electric utility business within the county limits, including Port Townsend. Since 1933, UtiliPoint and its predecessors have been providing the utility industry with a wide range of consulting and analysis services. In the past 25 years UtiliPoint has worked on dozens of municipal takeover attempts of electric utility businesses (known as "municipalization") around the United States.

This report and analysis was performed under the direction of UtiliPoint's CEO, Robert C. Bellemare. Mr. Bellemare has over twenty years experience in the electric power business and was an expert witness on engineering-related issues in two recent municipal takeover cases in Florida. During the past seven years, he has directed ten feasibility reports on municipal takeover attempts across the United States. Mr. Bellemare also has extensive electric wholesale and retail experience. As managing director of an energy services company, he oversaw the wholesale purchasing and retail pricing activities of a company that operated in several deregulated states and served on the corporate risk management committee for the parent utility. He has developed advanced generation dispatch algorithms for managing the fuel, transmission, and generation constraints for multi-area, multi-state/power pool operation and has been responsible for executing short (spot) and long term deals in several electric wholesale markets in the United States. Mr. Bellemare has developed generator economic models, performed asset valuation analyses, and developed fuel procurement and contract models. He has managed two large scale solar and wind energy research projects and worked as an engineer at one of the country's largest coal/oil power plants. Mr. Bellemare has also worked in the areas of distribution engineering, and system protection and relay engineering. Mr. Bellemare holds a Master's Degree in electric power engineering from Georgia Institute of Technology and is a registered Professional Engineer in the states of Texas and Oklahoma.

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1.0 Executive Summary

Puget Sound Energy (PSE) has served the electric needs of customers within Jefferson County for over one hundred years. Under Washington state law, the Jefferson County Public Utility District #1 (the "PUD"), a municipal government, can be granted the authority to purchase the electric plant and facilities within the county limits. In early 2008, the PUD authorized a feasibility study for purchasing the electric business in anticipation of a public vote at the General Election in November 2008. If the public votes to authorize the PUD to provide electric service, it is expected the PUD will initiate condemnation action in 2009 to determine the public use and necessity of the proposed acquisition and the compensation owed PSE for the property acquired.

Because of the implications of a PUD takeover of its' utility business, PSE contracted with UtiliPoint International, Inc. to provide an independent preliminary financial feasibility analysis of the proposed acquisition by the PUD. This report provides insights concerning some of the engineering and potential financial consequences involved with a PUD takeover effort (known as municipalization) should the PUD move forward with exercising its authority to purchase. The key finding is **a PUD takeover of the electric utility will not financially benefit customers in Jefferson County and may in fact result in rate increases because of the high costs and lost economies-of-scale involved in a takeover.**

The format for the study is a single-year cash flow analysis. The single-year format is considered a "flunk test" model because it is based on a conservative set of assumptions made in the PUD's favor. The PUD's estimated cost structure is then compared to PSE's electric rates for customers within Jefferson County to examine the possibility of a takeover being financially feasible. If the "flunk test" model provides substantial positive cash flow results then more study may be warranted. If, however, the model shows negative cash flow results then the takeover attempt is considered unlikely to produce financial benefits for customers.

Section 2.0 of this report details the preliminary upfront cost estimate of approximately $77 million for the PUD to purchase PSE's electric utility business within the county limits, including Port Townsend. These preliminary acquisition cost estimates assume PSE will retain transmission and substation assets, while the PUD purchases the distribution assets within the county limits. Should the PUD decide to purchase the transmission and substation assets in the area, takeover costs may exceed $100 million. These estimates do not include additional compensation that PSE is likely entitled to for investments made to serve the county that will be rendered useless or economically impaired (known as “severance damages” and "stranded costs") as a result of a takeover. Actual costs may be higher depending on the outcome of further technical and financial analysis that would determine the overall impact of the acquisition on PSE and the costs associated therewith.

Section 3.0 provides preliminary estimates of the PUD’s utility annual cost structure if it were to form an electric utility. The estimates are provided by major cost categories in both annual dollar amounts and in a “¢ per kWh” (¢/kWh).

Section 3.0 shows that the PUD would face a potential annual debt payment of $5.8 million to finance the estimated $77 million of upfront costs, which translates into a retail cost impact of 1.9 ¢/kWh. When the debt payments are added together over the 30-year bond term the PUD’s total out-of-pocket cost over the 30 years can exceed $170 million.

In addition to debt payments, the PUD will also need to include in its rates the cost for operating the electric system. The most expensive component is the cost to purchase power on the wholesale generation electric market which is estimated as 4.8 ¢/kWh. The cost for wholesale power represents one of the greatest risks and uncertainties to the PUD when pursuing a takeover. The PUD will certainly attempt to qualify for Tier 1 power from Bonneville Power Administration (BPA). However the amount of Tier 1 power that will be available to Jefferson is uncertain. BPA has set aside only 250 mega-watts of average power (MWa) for newly formed public utilities and has reserved 40 MWa of that amount for newly formed tribal utilities, leaving only 210 MWa for other new public utilities within the four northwestern states of Washington, Oregon, Idaho, and Montana.

Although the PUD will almost certainly not be a utility by 2011 because electric utility condemnation cases normally take 4 to 8 years to resolve, 2011-2020 is used by UtiliPoint as a representative time period for the purposes of estimating average wholesale power costs. UtiliPoint uses a “best case” estimate of BPA Tier 1 power during the 10-year period by assuming no other public utilities form. This “best case” analysis determined Jefferson would receive an average of 64 percent Tier 1 power and 36 percent of power at a market price, that when averaged together cost 4.8 ¢/kWh. Getting the power to customers will also require the PUD to secure transmission and substations services, which UtiliPoint is estimating will cost an additional 1.2 ¢/kWh.

The PUD utility will also incur costs to operate the distribution system, which is estimated at 2.1 ¢/kWh, replace parts of the system as necessary or capital replacement, which is estimated at 0.6 ¢/kWh), incur expenses to replace PSE’s conservation and low-income assistance programs costing 0.2 ¢/kWh, and create a payment to Port Townsend to replace existing

Figure 1-1. Preliminary financial model result.

		$	¢/kWh
Total Revenues	**$**	**29,532,848**	**9.76**
Jefferson County PUD Preliminary Cost Estimate			
Wholesale Power	$	14,508,207	4.80
Transmission and Substation	$	3,519,282	1.16
Operating	$	6,352,850	2.10
Conservation/HELP Programs	$	650,509	0.22
Debt Service	$	5,808,823	1.92
Capital Replacement	$	1,868,462	0.62
City Utility Tax PILOT	$	569,697	0.19
ST Priv. and Utility Tax	$	1,775,810	0.59
Total Expenses	**$**	**35,053,640**	**11.59**
Net Cash Flow	**$**	**(5,520,792)**	**(1.83)**
% Rate Increase		**19%**	

Key Assumptions

Wholesale	*64% Tier 1, 36% Market*
Operating	*$350 per customer*
Debt Service	*Takeover costs $77 million*
Capital Replacement	*RC * depreciation*
Rates	*PSE receives full request*

utility related taxes and other taxes such as the state utility tax (total taxes of 0.8 ¢/kWh). Estimates for these various cost items total to 3.7 ¢/kWh.

Section 4.0, and Figure 1-1, summarizes the preliminary financial feasibility results. The various cost components estimates of Section 3.0 total to 11.6 ¢/kWh, compared to PSE's forecasted 2009 rates of 9.8 ¢/kWh (inclusive of utility related taxes). The financial model demonstrates that the cost structure for the PUD is expected to exceed PSE's 9.8 ¢/kWh forecasted electric rates, resulting in a potential rate increase of 19 percent. UtiliPoint notes, however, that during the first 3 years of operation, the PUD will likely be required to purchase power at market prices because BPA power at Tier 1 rates will not be available to them. With today's escalating energy prices, wholesale costs could well exceed 8 ¢/kWh, which would represent a potential rate increase of 50 percent or even higher.

The report finding that a PUD takeover of the electric utility is unlikely to be feasible is further reinforced by the brief history of the utility industry and the track record of municipalization presented in Section 5. Since the 1940s there have been very few electric utilities formed of any kind, including new municipal electric utilities. The track record for trying to form a new municipal electric utility has a near 100 percent failure rate. Such efforts usually end for a myriad of reasons including lack of citizen support, the years and cost of legal proceedings, or because the actual costs involved exceed early expectations.

Forming a new municipal electric utility by taking over an existing utility is a daunting challenge. The reality is no viable business will be purchased at bargain basement prices. The premium paid to acquire the business and lost economies-of-scale normally overweigh advantages a city or PUD may have, such as lower financing costs. UtiliPoint concludes that a takeover of the electric business in Jefferson County is unlikely to financially benefit the PUD and customers and therefore it is not in the public interest to pursue such an effort.

2.0 COSTS INVOLVED IN PURCHASING THE ELECTRIC SYSTEM

A PUD incurs costs in several categories when acquiring an electric system and establishing a utility. PSE is entitled to compensation for the acquisition of its distribution facilities within the county limits of Jefferson County. In addition, the PUD will incur expenses as part of the legal proceedings and subsequent startup costs to establish the utility.

The cost items associated with completing a takeover normally include:

- Just Compensation for Distribution Assets - the value of the distribution assets being acquired, including the "going concern" value of these assets;
- Startup Expenses - includes land and building acquisition/construction, billing system installation and setup, customer services, metering, and phone systems;
- System Separation - severance damages and other costs to the PUD for reconfiguring the distribution system to maintain safe and reliable operations for both PSE and the PUD;
- Severance Damages and Stranded Costs – compensation to PSE for economic damages done to investments made to serve customers such as transmission and generation assets;
- Legal and Consulting Fees – costs for legal proceedings to acquire the assets and to establish the compensation owed to PSE.

The analysis in this report shows the preliminary cost for the PUD to take over the electric system is estimated at approximately $77 million exclusive of any severance damages and stranded cost award. UtiliPoint notes, however, that much higher takeover costs are possible, because UtiliPoint used conservative estimates where applicable. For example, UtiliPoint's takeover cost estimate does not include transmission and substation assets in the county. Acquiring these assets would likely push the takeover costs over $100 million.

Figure 2-1. Preliminary cost estimate for Jefferson County PUD to acquire PSE's electric business within the county limits.

Distribution Assets	$	46,502,862
Startup Costs	$	10,000,000
Going Concern	$	15,247,638
Separation	$	2,500,000
Legal, Consulting	$	3,000,000
Total	**$**	**77,250,500**

*Severance damage and stranded costs not included

The total of these costs will drive the bonding requirements and, therefore, the debt service payments for the PUD. Severance damage and stranded costs are left out of the current analysis because these costs will not be decided until extensive litigation is completed. Based on previous case history these proceedings can last several years. Additionally, the analysis will show that even without including stranded costs in the analysis, a takeover attempt by the PUD is unlikely to be economically feasible.

2.1 The PUD's "Authority to Purchase"

Under Washington law, a PUD has the authority to purchase the electric utility plant and facilities within its county limits, and this authority includes the power to acquire through a condemnation legal process. While the PUD has the authority to purchase, the amount of compensation owed to PSE is generally defined as "just compensation," and in the case of a municipalization there are a number of factors to be considered in arriving at "just compensation." Most government takeover cases have been resolved in a "contested" fashion, meaning the government entity and incumbent utility are unable to come to agreeable terms on their own and therefore the government entity initiates the legal process of condemnation to determine the scope of the acquisition and the compensation owed to the incumbent utility. Because of the likely difference of opinion between PUD and PSE experts on these issues, it is similarly assumed the PUD will need to initiate a condemnation proceeding. Such condemnation awards are subject to appeal and therefore can take (and are expected to take) years to complete.

2.2 Distribution Electric System Value

One approach, but not the exclusive approach, to value distribution assets under Washington law is replacement cost new less depreciation ("RCNLD"). In a litigation process, calculating an RCNLD value normally requires a system inventory, which is beyond the scope of this study. As a result, UtiliPoint uses a close cousin to RCNLD called Reproduction Cost Less Depreciation (RCLD) to develop a preliminary estimate of the distribution assets value within Jefferson County of approximately $47 million.

The RCLD methodology is utilized because such a preliminary estimate for the distribution asset value can readily be calculated from publicly available data. RCLD takes the Original equipment Cost Less Depreciation (OCLD), or book value, and applies an inflation factor (the Handy Whitman Index) to estimate the cost to reproduce the distribution system at today's prices as shown in Figure 2-2.

Normally RCLD and RCNLD calculations result in similar asset valuations however significant differences between RCLD and RCNLD valuations can arise if extensive technological changes have occurred since the system was originally constructed. With today's rising cost of new equipment relative to the original cost of equipment purchased years ago it is possible the RCNLD calculation would produce higher valuation results when compared to RCLD calculations.

Figure 2-2. Distribution Assets Value Estimate (RCLD methodology)

Original Cost	$	2,559,312,923
- Depreciation		35.21%
Net Book Value	$	1,658,184,783
x Handy Whitman (13 years)		1.62
RCLD	$	2,686,259,349
PSE 2007 Customers		1,048,402
Customer ratio (RCLD/PSE customer)	$	2,562
Number of Jefferson County customers		18,151
Jefferson County RCLD	$	46,502,862

Notes: *2007 FERC Form 1 data used to calculate original cost, depreciation, and average age (13 years). Land, Structures, and Station equipment FERC accounts (360, 361, and 362) not included.*

The RCLD estimate for the Jefferson County distribution assets was created by allocating PSE's system average distribution book value on a customer ratio basis (the ratio of the number of customers in Jefferson County to PSE's total number of customers) and then applying the RCLD methodology.

The valuation calculation used here is an approximation that can only be refined after a complete system inventory is concluded. The estimate of distribution system value also does not include the possible purchase of existing substations within the county limits by the PUD. The purchase of substation assets is impacted by many factors, including the design of exactly how the electric system within the county limits will be separated from the system outside the county limits. This separation design is a complex study normally completed during the legal proceedings. For the purposes of this report the potential cost of substation related issues is handled as part of the electric transmission cost analysis.

2.3 Real Estate, Easements, Maps, Records, and Startup

The RCLD calculation does not include compensation for buildings, land, easements, maps, manuals, and system records. Although very unlikely, the PUD may decide to not purchase these items from PSE. More likely, however, the PUD will purchase certain items from PSE. In a recently completed takeover case in Florida, the City of Winter Park paid the electric utility company over $10 million dollars in compensation for these items. By contrast, Winter Park paid $9 million for the distribution assets based on the RCLD approach.

In addition to purchasing land and real estate from PSE, the PUD would incur other startup costs such as buying additional land and constructing or buying other buildings. Among other things, the PUD would also need to set up its billing system, possibly modify its metering infrastructure, establish an inventory of equipment, and pay for or develop programs to replace PSE's programs such as load management and other specialty rates and incentives.

Jefferson County PUD is roughly the same size as Winter Park, so UtiliPoint very conservatively assumes that the compensation owed for these items and startup costs will be $10 million, although certainly much higher values are possible.

2.4 Going Concern

UtiliPoint estimates the PUD will owe $15 million in going concern compensation. Going concern value includes, among other items, the value of assets to generate future income and cash flows.

There are numerous methods for estimating going concern value. The more complex methods involve detailed simulations of cash flows and present value calculations, which are normally only completed at the time of litigation. UtiliPoint therefore uses a simplified approach for the limited purposes of this preliminary feasibility analysis for estimating going concern value. The calculation starts by estimating the annual cash flow a business would create for a buyer and then dividing by the buyer's cost of capital. The value for tangible asset is then deducted from this calculation to produce an estimate of going concern value.

UtiliPoint conservatively assumes the PUD would pay approximately 0.5 times the annual revenues in going concern compensation, or $15 million. This would represent an assumption that PUD would expect about 11.5 percent rate "savings" (or potential financial benefit) to support the forming a new electric utility, which would represent a $3.4 million cash flow. Dividing $3.4 million by the PUD's estimated cost of capital of 5.5 percent results in a value estimate of $62 million. Deducting the distribution value estimate of $47 million, the going concern value is $15 million.

The going concern value of a utility normally ranges to as high as 2.5 times the annual revenues from the business. $15 million represents only a 0.5 times the annual revenues of $30 million, so the $15 million is likely conservatively low.

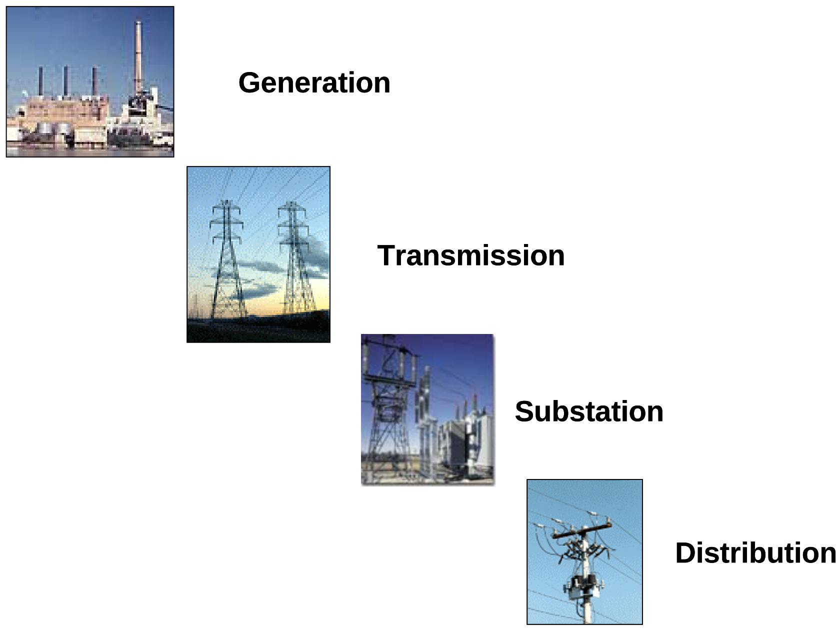
The 2.5 multiplier of revenues is the level of going concern type compensation that is sometimes found in what are called territorial agreements between neighboring utilities. Territorial agreements often draw boundary lines that define, for example, Utility A will serve all customers on one side of a boundary and Utility "B" will supply all customers on the other side of a boundary. Territorial agreements sometimes contain formulas (such as a going concern component of 2.5 times annual revenue) for how much a utility will owe the other utility where the utility desires to acquire or serve customers on the other side of the boundary that would normally be served by the other utility. Typically, these situations occur where it would be more efficient for a utility to serve the customer or customers that would otherwise normally be served by the adjoining utility.

2.5 Electric System Separation

A proposed acquisition normally requires PSE to reconfigure its remaining power system and operation practices to ensure the safety and reliability of service to its remaining customers outside the county limits. This would be a severance damage for which PSE is entitled to compensation. However, for the purposes of this preliminary assessment, it is assumed that PSE may only be required to disconnect its submarine cables from Jefferson County at little or no cost. Jefferson County, however, will need to invest in the distribution system to replace the functionality of the submarine cables or reach agreement with PSE to continue using these submarine cables. Without the submarine cables, providing reliable service to these areas may require rebuilding ten or more miles of distribution line. UtiliPoint uses a $2.5 million budget for the power system reconfiguration.

The electricity needed to serve a community is typically generated at distant power plants. The generated electricity flows from the power plant along high voltage transmission lines (typically 115,000 to 500,000 volts). Substations, containing large transformers, drop the voltage down to what is called distribution voltage levels (typically 12,470 to 23,000 volts). The distribution system is the poles and wires normally seen on most streets and takes the electricity from the substation and delivers it to most customers. For residential customers the voltage is further reduced to 120/240 volts by transformers that look like large cans on distribution poles or boxes located on the ground if the distribution system is underground.

Figure 2-3. Power System Design Basics.



The transmission system in Jefferson County has a complex ownership structure, with PSE, Clallam County PUD, and BPA each owning facilities in the region. The transmission system serving the region originates at BPA's Fairmount substation, which imports nearly all the electricity consumed in Jefferson County using BPA's 230,000-volt transmission system. Transformers in the Fairmount substation drop the voltage to 115,000 volts. This 115,000-volt transmission system delivers power to the seven PSE's distribution substations scattered throughout Jefferson County. These PSE distribution substations contain transformers that further reduce the voltage to 12,470 volts and all the distribution lines originating from PSE's substations exclusively serve customers within Jefferson County.

Figure 2-4. BPA's Fairmount Substation.

Complex agreements between PSE, BPA, and Clallam County govern the rights to use the system. As an example of this complexity, Clallam County PUD owns and operates a 115,000-volt transmission line that originates from Fairmount substation. This line supplies PSE's Discovery Bay distribution substation and Port Townsend Paper. Clallam County PUD's, the Port Townsend Mill, and PSE's transmission facilities in the region are also used to provide backup services to each other under an agreement between Clallam, Port Townsend Paper and PSE. In this preliminary analysis, UtiliPoint has not evaluated the constraints these agreements may impose upon the PUD's ability to take delivery of power from BPA at the Fairmount Substation, nor has UtiliPoint considered the time and cost associated with transmission upgrades that could be required if additional transmission capacity is needed. For the purposes of this preliminary analysis, UtiliPoint has made a favorable assumption that the PUD will be able to take transmission service from PSE and Clallam. The PUD will, however, need to look carefully at the transmission physical and contractual constraints and potential upgrades in connection with any recommendations to move forward with an acquisition of PSE's distribution system which would represent additional costs not considered in this report.

Figure 2-5. PSE (left side) and Clallam County (right side) 115,000-volt transmission lines near PSE's Irondale substation.

While most customers within Jefferson County are served from the existing distribution system within Jefferson County, there are two 12,470-volt distribution submarine lines connecting the distribution systems in Jefferson and Kitsap Counties. One line is near Hood Canal Bridge, which is the main power source for Jefferson County in that area. The other line crosses the Hood Canal on the southern end of Toandos Peninsula, serving Navy facilities and other customers in that area. Distribution systems of one utility are rarely used to routinely serve customers in another utility's area, so in a municipalization, typically the system will be redesigned so that routine service will be provided from distribution facilities located under control of the acquiring government entity (the PUD) . One possibility would be to reconstruct more than 10-miles of an existing single-phase distribution line in Toandos Peninsula to be a three-phase line that would then serve the area from PSE's Quilcene substation located in Jefferson County. The distribution system in the Hood Canal Bridge area can possibly be reconstructed to take service from distribution lines solely with Jefferson County that originate from the Port Ludlow substation. Backup sources of power, may, however be an issue to maintain reliable electric service so either agreement with PSE must be reached to provide such service from the existing submarine system, or the PUD may need to construct miles of new distribution lines to the areas. Only after extensive study would a separation plan be developed to address these issues, however UtiliPoint has conservatively budgeted $2.5 million.

2.6 Stranded Costs

One reason that a city or county might consider forming a municipal electric utility is to directly access the electric wholesale market. The United States Energy Policy Act of 1992 (EPA 1992) gave the Federal Energy Regulatory Commission (FERC) the authority to order transmission owning utilities to provide transmission service to any electric utility or person generating electricity that sells power to a wholesale buyer, such as a municipal electric utility. Transmission assets are the high voltage power lines (normally 115,000 volts or greater) that deliver bulk power to distribution substations. In response to this Act and FERC directives, PSE and other transmission owning utilities have filed what are known as Open Access Transmission Tariffs (OATT) with FERC.

Stranded costs can occur when an asset is rendered useless or impaired by the taking or purchase of private utility property by a government entity. These costs are a form of severance damage for which PSE is entitled to compensation. Broadly speaking, stranded costs are investments made on behalf of customers to ensure future electric service that are rendered uneconomic when those customers leave the system. Stranded costs are distinctly different from going concern value. Stranded costs are calculated based on capital investments in assets such as generation, transmission, and distribution that are dedicated to providing service to customers. Using standard accounting methods, these investments can be allocated to customers in a specific geographic area. The term "stranded costs" is often used in relation to stranded generation assets – although many other kinds of assets can come under the umbrella of this definition.

Subsequent to EPA 1992, FERC issued Order 888, in which FERC asserts jurisdiction over stranded costs (or "economic damages") that result from the formation of a new municipal electric utility such as the one the PUD of Jefferson County is considering. The condemnation court historically has and will consider compensating PSE for these costs as a form of severance damage. However, FERC is claiming that both it and states have legal authority to address this issue when a PUD or city forming a municipal utility receives transmission service under OATT, for example, to form the new municipal utility.

When determining stranded cost, FERC considers whether the utility had a reasonable expectation of continuing to serve the customers within the city or county. FERC has cited several factors it would consider when deciding the reasonable expectation to serve, including whether state law awards exclusive service territories and whether state law imposes a mandatory obligation to serve. In a failed municipalization attempt by the City of Las Cruces, New Mexico, FERC found in its May 26, 1999 opinion that the utility did have a reasonable expectation of continuing to serve Las Cruces, even though its franchise agreement with that city had expired in March 1994.

If FERC finds that the utility had a reasonable expectation to continue serving, then it will attempt to quantify the amount of stranded costs owed by applying a "revenues lost" formula. The revenues lost formula is:

Stranded Cost Obligation =
(Revenue Stream Estimate - Competitive Market Value Estimate) x Length of Obligation

This is a simple formula in appearance, but great legal debate is made over each of these factors. The revenue stream estimate can be assessed by taking the average annual revenue collected by the incumbent utility from the departing customers, less the average transmission and distribution revenues that the incumbent utility collects after municipal electric utility is formed. The "Competitive Market Value" is an estimate of revenue, or market price, which the utility would receive if it is able to sell the released generation capacity and energy to others. This estimate is particularly difficult to assess because wholesale market prices are very volatile.

Quantification of stranded costs is difficult at this time because the valuation of economic impacts is heavily dependent on electric wholesale market price forecasts. With an expected five or more year purchase and legal process, a market price forecast is likely to change considerably over this time period. These costs can, however, be very large. In the City of Las Cruces takeover case, with a current population of 85,000, FERC awarded over $52 million in stranded generation costs alone. Although some viewed this amount as conservative, the award more than doubled the city's final projected costs to acquire the electric system from El Paso Electric. In Winter Park's case, arbitrators ruled the amount owed totaled over $10 million, but the total amount declined based on the year of the actual takeover. In other words, if Winter Park formed a municipal utility in 2003 it would pay a higher stranded cost than if it formed the utility in 2004. Winter Park's distribution asset value was set at $9 million, so stranded costs alone can easily exceed the compensation paid just for the assets.

Given the high level of uncertainty in this calculation and the ever changing wholesale market prices, no attempt is made in this report to quantify the damages FERC will provide as a result of the PUD actions. As a result of this transaction, other economic damages may occur, such as the idling of PSE facilities or the loss of contribution from customers residing in the PUD towards fixed costs such as billing systems, customer call centers, etc. These and other costs, sometimes referred to as severance damages, are not considered in this report but would likely arise when more complete investigations are made during the legal proceedings. As the analysis will show, the PUD's attempted purchase of the electric utility business within the county limits is economically infeasible even before a stranded cost or severance damage determination is made.

2.7 Legal and Consulting

The legal process for establishing the purchase price of the system is normally lengthy, costly, and involves numerous governing bodies, sometimes with conflicting or unclear authority. Washington state courts and the Federal Energy Regulatory Commission (FERC) may each be involved in determining the level of compensation the PUD owes PSE for different purchase elements discussed in this report section. In addition, under Washington law, the PUD may be responsible for PSE's legal costs and fees, as well as its own costs and fees.

Nationally, cities that have attempted contested takeovers have also faced an uncertain legal path as illustrated in Figure 2-6. Based on a comparison of costs incurred in other recent contested takeovers, a county the size of Jefferson can conservatively expect approximately $3 million in legal and consulting expenses to complete its takeover attempt. This estimate assumes that the condemnation process was successful in settling the amount of compensation owed.

Figure 2-6. Legal and consulting fees in major municipalization cases.

City/State	Total Amount Spent (Actual Year Dollars)	Dates	Current Population	Status
Chicago, Illinois	$12 Million *Public Utilities Fortnightly, Sept 15, 1994*	1986-1991	2,783,726	Failed
Las Cruces, New Mexico	$8.5 Million (legal, engineering, bond interest) *Ruben A. Smith, Mayor of Las Cruces, March 26, 2000* • $5.7 Million of the $8.5 Million total was for legal and engineering, based on other public statements	1990-2000	78,000	Failed
Massena, New York	$2.2 Million • $1 Million to Legal • $1.2 Million to Consultants *Public Power, Sept-Oct 1986*	1973-1981	13,826	Completed
New Orleans, Louisiana	$10 Million • $6 Million to Legal • $4 Million to Consultant *Public Utilities Fortnightly, Sept 15, 1994* *Electric Utility Week, June 25, 1990*	1983-1990	468,124	Failed
Winter Park, Florida	Over $3 Million *Winter Park reported $2,856,026 was spent through 9/30/2003.*	1999 – 2005	24,090	Completed

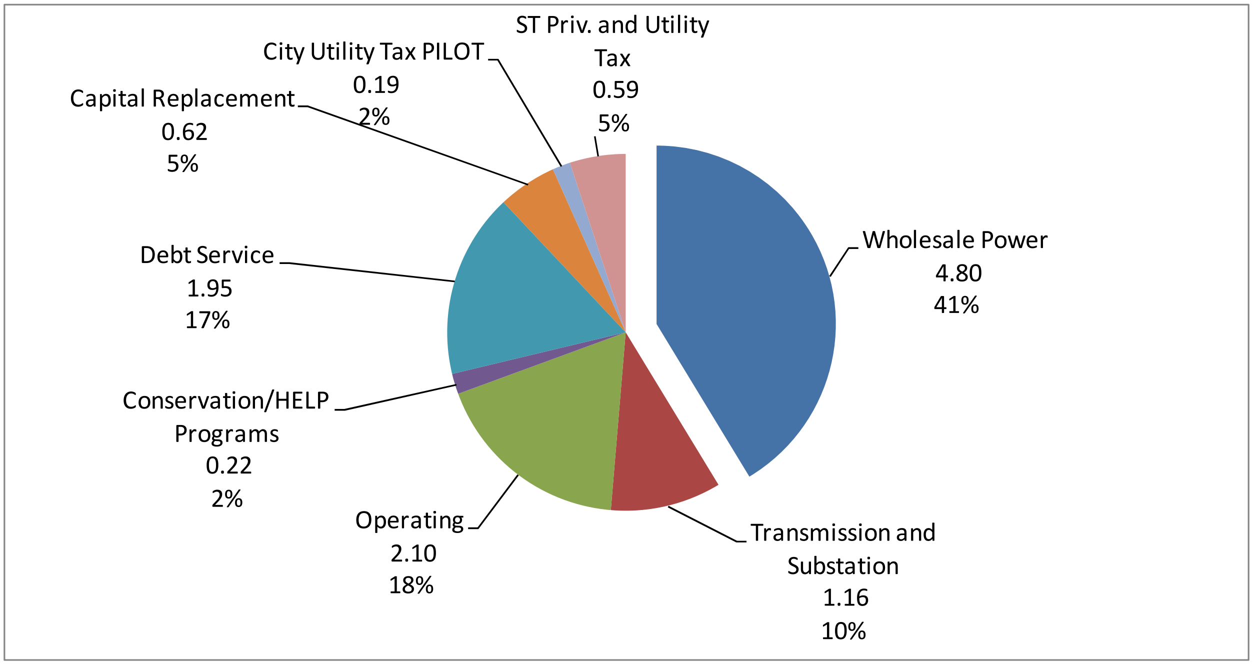
3.0 Utility Estimated Annual Expenses

This report section provides a preliminary estimate of the operating cost structure for the PUD of Jefferson County should it complete a takeover of PSE's electric systems. Important customer data such as the number of customers, energy consumption, and peak demand are first estimated because they drive the calculation of annual expenses. These annual utility expenses for a newly formed municipal electric utility are then examined by their major categories, including:

- Wholesale Power – The cost for purchasing or generating electricity plus the transmission and substation costs required to send that electricity to the delivery points within the PUD.
- Operating Expenses – The cost to operate and maintain the distribution system plus the costs for administration and customer care functions such as billing.
- Renewal and Replacement Capital – Investments required to replace damaged or failed parts, storm repairs, to replace parts beyond their economic and functional life, and to keep pace with demand growth.
- Debt Payments – Loan payments on the debt incurred to fund the acquisition costs.
- Taxes – A "Payment in Lieu of Taxes" (PILOT), and other forms of taxes to replace city utility taxes, property taxes, and other taxes.

Figure 3-1 represents a possible case of the PUD's utility cost structure should it take over the electric business. As illustrated, wholesale power costs dominate the cost structure, representing over forty-percent of annual expenses. The next major cost component is the debt payment on bonds issues to finance the purchase of the electric utility business which can represent fifteen-percent or more of the newly formed municipal's cost structure. The potential feasibility of a utility takeover is, therefore, driven in large part by wholesale arrangements and the costs involved in acquiring the electric systems.

Figure 3-1. Jefferson County annual expenses (representative).



Data labels provide the ¢/kWh and the percentage of total expenses each item represents.

3.1 Jefferson County Customer Data and Peak Load Estimate

Several important customer statistics are needed to estimate the operating costs for a PUD-run electric system. PSE provided UtiliPoint with actual customer data for the 12-month period ending December 2007. This data does not include the Port Townsend Mill, which is located in Jefferson County but is currently served by Clallam County PUD. UtiliPoint then modeled possible rate adjustments (including assuming PSE receives its full rate increase request for the pending rate case less the $100 million over 10-year period rate reduction PSE recently offered) and assumed a 2 percent annual growth rate to prepare a 2009 customer data estimate. The 2003-2007 average annual kWh growth rate in Jefferson County was 3.7 percent, however UtiliPoint is using 2 percent because it is expected the growth rate in the County will drop. The 2009 estimate shows Jefferson County having 18,151 customers, with 302,472,975 kilowatt-hours (kWh) in annual sales. The average annual price per kWh charged by PSE to customers within the Jefferson County is forecasted to be 9.76 ¢/kWh, inclusive of state and city utility taxes.

Figure 3-2. Jefferson County data forecast for 2009.

	Customer Data Forecast for 2009						
	Accounts Billed	**kWh**		**Total Billed ($)**	**¢/kWh**		**Taxes ($)***
Residential	15,309	206,010,236	$	20,798,683	10.10	$	1,206,746
Commercial	2,701	93,049,828	$	8,328,331	8.95	$	483,212
Industrial	95	2,910,362	$	284,795	9.79	$	16,524
Other	46	502,549	$	121,039	24.09	$	7,023
Total	**18,151**	**302,472,975**	**$**	**29,532,848**	**9.76**	**$**	**1,713,505**

** Assumes kWh growth is (2%), note the annualized growth rate during 2003-2007 was (3.7%)*
** Includes proposed 2008 rate change*

A very important driver of utility costs is the annual peak electric demand. Utilities must plan and build to serve this annual peak demand and many charges in the industry are calculated based on monthly and annual demands. UtiliPoint estimates the annual "retail" peak demand in Jefferson County is about 76 MW by assuming the demand characteristics in the County are similar to the entire PSE system. "Retail" peak demand, however, must be adjusted to accommodate for electric losses on the distribution and transmission systems when calculating wholesale power supply and transmission charges. UtiliPoint estimates the loss adjusted peak demand as 81 MW.

3.2 Wholesale Power Supply

The components of generation, transmission, and transmitting power through the electric substations that serve customers are the most costly component of electric service. When analyzing these potential costs to the PUD of Jefferson County, UtiliPoint assumes BPA will supply power to the PUD in a combination of "Tier 1" and market based rates. UtiliPoint estimates the PUD's annual wholesale expense under a "best case" scenario at $14.5 million, or an average of 4.8 ¢/kWh delivered to the customer meter ("retail").

UtiliPoint estimates Jefferson County's annual electric load will exceed 40 MW average (MWa). BPA has proposed to set aside 250 MW average (MWa) of "Tier 1" power for newly formed public utilities. 40 MWa of that amount is allocated to tribal utilities, leaving only 210 MWa for other newly formed public utilities. "Tier 1" power is desirable because it will likely be available at a lower cost compared to market prices for power generation today – approximately 3 ¢/kWh. BPA's policy for Tier 1 power for the next contract cycle are still under development. Proposed policies, however, address the following key requirements:

- the PUD is required to make a 3-year binding notice that it wants to receive service from BPA,
- the amount of Tier 1 power a newly formed public can receive is capped to the average percent of Tier 1 power current subscribers are receiving,
- the total set-aside is 250 MWa, which will be phased in over five 2-year periods of 50 MWa each,
- large new publics (over 10 MWa) will generally be expected to phase in over the 5 periods,
- must contract for firm BPA transmission service and must satisfy BPA's "service standards" such as demonstrating the financial ability to pay BPA for the power it purchases.

There are several implications of the Tier 1 process for a newly forming electric PUD of large size (over 10 MWa):

- It will likely take several years to complete the litigation process for purchasing PSE's facilities to satisfy BPA's Standards of Service. UtiliPoint is modeling that the PUD will be seeking to contract for Tier 1 power in 2011, and must then wait 3 years (until 2014) before receiving any Tier 1 power. UtiliPoint notes, however, that it is very unlikely the PUD will actually be a utility in 2011 since takeover cases normally take 4 to 8 years to resolve.
- There is a risk that the 250 MWa "new" Tier 1 will be fully or partially subscribed by the time the PUD is in the position to contract for power, thereby further limiting (or entirely eliminating) the amount of Tier 1 power available to the PUD.
- BPA's transmission access may not be available, which may also limit or eliminate the amount of Tier 1 power available.

If Jefferson County's load grows at an annualized rate of 2 percent per year, then by 2014 the generation requirements would be 41 MWa inclusive of electric losses to the delivery point of the BPA transmission system. Using best case assumptions*, Jefferson County's wholesale power supply from Tier 1 power resources would be as follows:

Year	*2011*	*2012*	*2013*	*2014*	*2015*	*2016*	*2017*	*2018*	*2019*	*2020*
Load (MWa)	39	40	40	41	42	43	44	45	46	46
Tier 1 (MWa)	0	0	0	39	39	39	39	39	39	39
% Tier 1	0	0	0	95%	93%	91%	90%	88%	86%	84%

** assumes there are no other newly formed government utilities requesting Tier 1 service in the Northwest States, and BPA caps Tier 1 at 95 percent. The load is estimated as the average MW (MWa) at the BPA delivery point (includes an estimate of electric losses on the transmission and distribution system) and the amount is fixed at 39 MWa.*

The weighted average for the 2011 through 2020 period PUD is 64 percent Tier 1 power. For the purposes of the financial model, UtiliPoint utilizes the best-case scenario that 64 percent of Jefferson PUD's power supply needs are at Tier 1 rates estimated at 3.0 ¢/kWh with the remaining amount coming at a market price. The market price forecast is taken from PSE 2007 IRP Plan, which forecasts a price for long-term wholesale power in 2009 at 7.65 ¢/kWh.

BPA's Tier 1 power does not include required "ancillary services" for items called operating reserves, supplemental reserves, and regulation and frequency control. UtiliPoint includes a cost estimate for these services based on PSE OATT tariff rate totaling to $4.5756 times the 2009 annual peak demand estimate of 81,000 kW, for a $0.4 million annual cost. UtiliPoint used PSE's charges rather than BPA's because BPA's charges for these services would have been 6 times higher than PSE, so again UtiliPoint has made a conservative assumption in the PUD's favor.

The total cost estimate for wholesale power in the financial model is $14.5 million. The calculation assumes 64 percent of Jefferson PUD's kWhs (0.64 *303 million kWh, or 194 million kWh) costs 3 ¢/kWh with the remaining 109 million kWh costs 7.65 ¢/kWh, for a total of $14.1 million. The "ancillary services" cost estimate is then added to that amount for a total cost estimate of $14.5 million.

UtiliPoint notes that Jefferson PUD #1 would be subject to Washington's renewable resource targets when it reaches the threshold of serving twenty-five thousand customers. The potential cost of meeting renewable resource targets were not included in UtiliPoint's wholesale cost estimate.

3.3 Transmission and Substation Service

Jefferson County PUD #1 will need to reserve and pay for transmission service to move power from generating plants to BPA's Fairmount Substation in the County. In addition, the PUD will either purchase PSE's transmission system and distribution substations in the County as part of the litigation process or PSE will retain ownership of these assets and provide transmission and substation service to the PUD. UtiliPoint's financial feasibility analysis assumes PSE will retain the assets since the annualized cost will likely be similar under either scenario. The total annual cost for transmission service is estimated at $3.5 million or 1.2 ¢/kWh.

Delivering power to Jefferson County would require both PSE and Bonneville Power Administration (BPA) transmission facilities. The charges for transmission service are spelled out in what are called Open Access Transmission Tariffs (OATT). PSE's charges for "point-to-point" transmission service total to $0.9/kW-month which results in a PSE transmission service cost estimate of $0.9 million when taxes and other applicable charges are added.

BPA's OATT charges would total to $1.868 per kW of peak demand each month. One-way to estimate the annual total is to take an estimate of the average monthly billing demand, multiply by $1.868 and then by 12 (because there are 12 months in a year). UtiliPoint examined PSE's energy usage and demand data available on FERC-Form 1 and concludes that the average demand will be approximately 78 percent of Jefferson County's 2009 estimated annual peak demand of 84 MW inclusive of electric losses. Therefore the BPA transmission service cost is estimated to total to $1.4 million ($1.868*12*81,000 kW * 0.78).

To estimate the cost of renting PSE's substations, UtiliPoint examined several rate structures and other cost estimation approaches, and conservatively used an estimate of $14.5 per kW-year as the cost for substation service, which provides a $1.2 million per year substation rental cost estimate.

3.4 Annual Bond Payment

One of the largest components of electric rates will be the principal and interest payment on the debt incurred to finance the takeover as prescribed in the bond indenture requirements. It is assumed that the PUD will use 5.5 percent interest, long-term (30-year) A&B notes to finance its takeover effort. The cost for issuing a bond averages approximately 0.875 percent of the bond amount. Additional transaction fees are assumed to be 2.9 percent of the bond amount. It is also conservatively assumed that the PUD will be required to carry 10 percent of the bond amount in cash reserves at an "effective" interest rate cost of 2 percent and a 30-year term. The “effective” interest rate is meant to reflect the difference between the borrowing interest rate and the interest rate a PUD will earn on the reserves. The resulting annual bond payment does not include any bonding requirements that would be driven by stranded costs or other severance damages that have been excluded from our analysis. The system acquisition bonding requirements are estimated at $5.8 million per year as developed in Figure 3-3 below, representing a 1.9 ¢/kWh cost impact.

Figure 3-3. Bond Requirement and Fees - System Acquisition

Debt service for system purchase				Average
Takeover cost estimate			$	77,000,000
Transaction costs	2.875%	bond	$	2,279,279
Total Bonding Requirement			$	79,279,279
Principal & interest				
Interest rate	5.50%			
Term	30			
Annual Bond Debt Payment			$	5,454,842
Reserve fund requirements		10.00%	$	7,927,928
Reserve Fund Principal & interest				
"Effective" Interest rate	2.00%			
Term	30			
Annual Reserves Cost			$	353,981
Debt Service for System Purchase			**$**	**5,808,823**

3.5 Distribution Operating, Customer, and Administration Expenses

In recent takeover studies conducted by UtiliPoint, it was found that a $300 to $400 per customer annual cost would be expected to cover expenses such as distribution operating, customer service, and general and administration expenses. UtiliPoint examined the 2006 annual reports for primarily electric PUD's Okanogan and Franklin County. Okanogan County PUD serves 19,800 electric customers and its distribution operating related expenses are approximately $358 per customer. Franklin County PUD serves 20,823 customers and its expenses average $416 per customer. For the purpose of this report, UtiliPoint uses $350 per customer cost as an estimate of distribution operating related expenses, resulting in a cost estimate of $6.4 million ($350 * 18,151 customers) and a cost impact of 2.1 ¢/kWh.

3.6 Conservation and HELP Program Expenses

UtiliPoint assumes the PUD will replace PSE's energy conservation and HELP Low Income Bill Assistance Program programs. Under RCW 19.285, Jefferson County is required to establish a conservation target once they reach 25,000 customers and then must pursue all cost-effective conservation efforts. For the purposes of the financial model, UtiliPoint assumes the PUD will continue the $650,000 of conservation and HELP programs in Jefferson County, representing a cost of 0.22 ¢/kWh.

3.7 Capital Replacement

The PUD will need to make annual investments in the distribution system to replace old equipment, repair damage from storms or accidents, and build new facilities to accommodate any load growth. UtiliPoint estimate for capital replacement is based on applying the depreciation rate to the Reproduction Cost (RC) because RC closely represents the cost of new equipment. The RC value is calculated by taking the Original Cost of the distribution system and multiplying it by the Handy Whitman Index. When allocated on a customer ratio basis to Jefferson County the RC value is $69 million. PSE's 2007 depreciation rate for distribution equipment was 2.71 percent. Multiplying $69 million by 2.71 percent gives an annual capital replacement cost estimate of $1.9 million. Another approach is to use PSE's FERC Form 1 data, accounts 101, 102, 103, and 106, for distribution equipment and apply the amount of "additions" to distribution plant on a per customer ratio to Jefferson County. The 2006 distribution investment, not including substation investments, was $138 per customer. Applying these ratios to Jefferson County suggests the capital replacement budget would range from $1.9 million to $2.5 million. UtiliPoint is conservatively using the lower of the two estimates, $1.9 million, representing a cost impact of 0.6 ¢/kWh ($1.9 million/302,472,975 kWh). The budget numbers developed in this report section are intended to reflect an "average" year, without major storm damage. There will certainly be years where actual expenditures will increase in response to damage done by major storms.

3.8 Payment in Lieu of Taxes (PILOT) and Other Taxes

In 2007, PSE paid utility taxes to Port Townsend in Jefferson County totaling to 1.93 percent of retail revenues in the County. This 1.93 percent tax would represent nearly $600,000 of the annual revenue estimate ($30 million) used in the financial model. In the feasibility financial analysis it is assumed the PUD will pay a payment in lieu of taxes (PILOT) to replace the $600,000 utility tax and state and local taxes including a Washington state privilege tax and a public utility tax that is a percentage of gross operating revenues.

The annual amount of PILOT expenses would be 0.2 ¢/kWh retail ($0.6 million/ 302,472,975 kWh). In addition, the PUD will be subject to a 2.14 percent state privilege tax which is intended to replace property tax payments and a 3.873 percent state utility tax. The annual state taxes would total 0.6 ¢/kWh retail ($1.8 million/302,472,975 kWh).

4.0 Financial Feasibility Discussion

Figure 4-1 illustrates that customers in Jefferson County are unlikely to financially benefit by a PUD takeover of the electric utility business. The model demonstrates that the cost structure for the PUD is expected to exceed PSE's 9.8 ¢/kWh forecasted electric rates, resulting in a potential average rate increase of 19 percent.

Figure 4-1. Preliminary financial model results.

	$	¢/kWh
Total Revenues	**$ 29,532,848**	**9.76**
Jefferson County PUD Preliminary Cost Estimate		
Wholesale Power	$ 14,508,207	4.80
Transmission and Substation	$ 3,519,282	1.16
Operating	$ 6,352,850	2.10
Conservation/HELP Programs	$ 650,509	0.22
Debt Service	$ 5,808,823	1.92
Capital Replacement	$ 1,868,462	0.62
City Utility Tax PILOT	$ 569,697	0.19
ST Priv. and Utility Tax	$ 1,775,810	0.59
Total Expenses	**$ 35,053,640**	**11.59**
Net Cash Flow	**$ (5,520,792)**	**(1.83)**
% Rate Increase	**19%**	

Key Assumptions

Wholesale	*64% Tier 1, 36% Market*
Operating	*$350 per customer*
Debt Service	*Takeover costs $77 million*
Capital Replacement	*RC * depreciation*
Rates	*PSE receives full request*

A single-year modeling approach was used because UtiliPoint believes if financial feasibility cannot be demonstrated using the most current and accurate information available, under the most favorable assumptions that could be made for a county, then the financial feasibility conclusions would not change in other types of analyses. The single-year financial model results show that the Jefferson PUD will have negative cash flows which may increase electric rates to customers in the County.

UtiliPoint did run a sensitivity analysis on the model results. To create a "breakeven" scenario, either the cost of wholesale power would need to fall from 4.8 ¢/kWh to 3 ¢/kWh or the cost to acquire the utility business would need to drop from $77 million to $10 million. Neither scenario appears feasible.

5.0 Historical Perspective

The report finding that a government takeover of the electric utility is unlikely to be feasible is further reinforced by the brief history of the utility industry and the track record of municipalization. Since the 1940s there have been very few electric utilities formed of any kind, including new PUD's or other government electric utilities. The track record for trying to form a new electric utility by taking the business from an existing utility through a process such as condemnation has a near 100 percent failure rate. Such efforts usually end for a myriad of reasons including lack of citizen support, the years and cost of legal proceedings, or because the actual costs involved exceed early expectations.

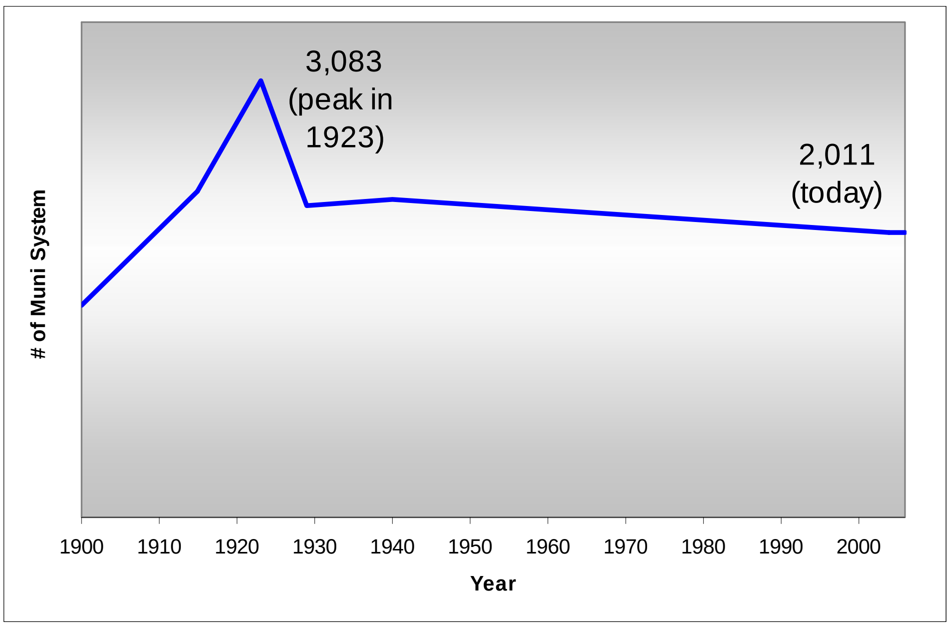
5.1 History

Municipally operated electric systems have been in existence since the late 1800s, when the modern electric utility industry began. They supplied street lighting and trolley systems for growing cities, peaking in numbers and share of total generation at the turn of the century.

From the turn of the century to the Depression, growth and progress in the evolving electric industry brought technological advances, greater economies of scale, and the beginning of State and Federal regulation. Systems and cities were able to interconnect with high voltage transmission lines, and new, more powerful steam generator designs came on line, making central station generation more economic than isolated municipal systems. Both the number of municipal utilities and their share of total generation dropped steadily, as they merged with or were absorbed by larger, more efficient privately owned systems.

In 1923, the number of municipal electric system peaked at 3,083 utilities. Since the 1930s, the total number of municipals has remained relatively stagnant; the latest figures available today from the APPA (American Public Power Association) count 2,011 municipal systems in 2006. These 2,011 municipalities serve nearly 20 million customers nationally, representing 14.4 percent of the nation's electric customers according to the Department of Energy's (DOE) Energy Information Administration (EIA).

Figure 5-1. Number of Municipal Electric Systems.



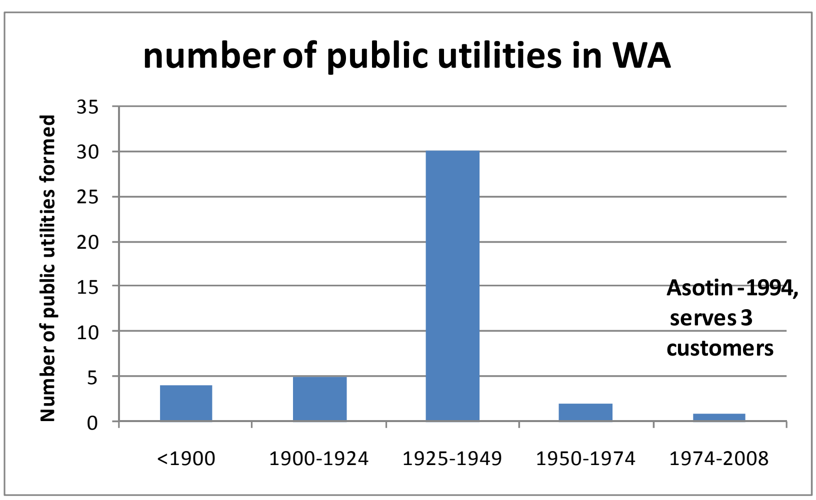
In the 1920s, private utilities also experienced consolidation, forming large utility holding companies, which at one time controlled over 75 percent of all U.S. generation. Industry consolidation ended in the 1930s due to the lack of capital available to finance acquisitions during the Great Depression.

A municipal forming today is not generally analogous to most existing municipal electric utilities. Early municipals and rural electric co-ops received access to low cost power sources and free or low cost and tax-free financing to encourage the electrification of rural communities.

In contrast to Investor Owned Utilities (IOUs), PUD's and other forms of government utilities are exempt from federal taxes. Government utilities can also issue 100 percent, low-interest rate debt to finance their capital needs, while IOUs generally use about 50 to 60 percent debt with the rest of the financing coming in the form of equity (shares). Although government owned utilities have a potential capital financing advantage, this advantage is normally dwarfed in a takeover effort because of the costs involved in the takeover typically exceed what is included in the IOU's current electric rates. A newly formed electric utility also typically does not have access to lower cost wholesale power when compared to the incumbent IOU. Without a wholesale cost advantage, the ability of a newly formed municipal to offer competitive rates is nearly impossible. These are some of the important reasons there have been very few municipals successfully formed in the past fifty years by condemning an existing electric business.

The history of municipals and public utility districts is similar in Washington. There have been few new public utilities formed since the 1950's. The last one was Asotin County PUD #1, which began electric service in 1994 but today only serves three retail customers.

Figure 5-2. Formation of Washington Public Power Electric Systems.



Source: American Public Power Authority (APPA).

5.2 Recent Municipalization Attempts

In the last several decades, nearly all attempts at forming an electric municipal system have failed when the takeover was contested by the incumbent utility. The causes of failure run from financial difficulties to lack of popular support. The following table illustrates the recent history of contested municipalization attempts and their results:

Figure 5-3. Examples of Recent Contested Municipalization Attempts

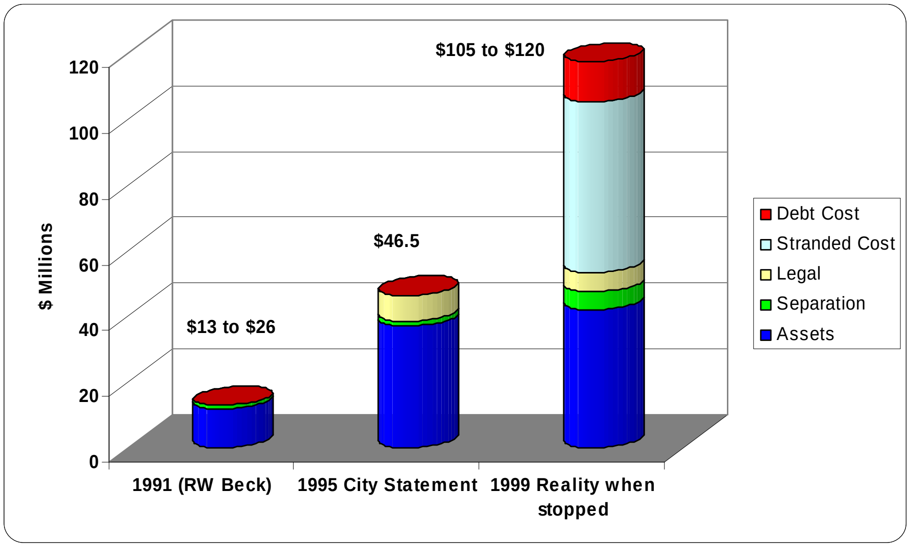
City	Utility	Date	Result
Yolo County, CA	PG&E	2006	Defeated in public vote
Iowa CITY, IA	Mid American	2005	Defeated 67% -33%
Pueblo, CO	Aquila	2005	Defeated in Council
Belleair, FL	Progress Energy FL	2005	Litigation completed but defeated by public vote, 54%-46%.
Winter Park, FL	Progress Energy FL	2005	Completed, recorded financial losses so far
Casselberry, FL	Progress Energy FL	2004	Litigation completed but new franchise with Progress signed
Elk CITY, OK	AEP	2002	Defeated: 55% - 45%
Wagner, SD	NorthWestern	2002	Defeated: 63% - 37%
Watford CITY, ND	Montana Dakota Utilities	2001	Referendum failed
San Francisco, CA	PGE	2001	Referendum failed
Wichita, KS	Western Resources	2001	Stopped after rate decrease
Hermiston, OR	Scottish Power/PacifiCorp	2001	Completed, rates higher than PacifiCorp based on 2006 data
Lakewood, NY	Niagara Mohawk	2000	Stopped after $14 M stranded cost ruling
Lakewood, WA	Puget Sound Energy	2000	Defeated in Council
Sloan, NY	New York State Electric & Gas	2000	Referendum Failed
Las Cruces, NM	El Paso Electric	2000	Defeated – Negotiated Settlement
Buffalo, NY	Niagara Mohawk	1998	Defeated in Council
Berthoud, CO	Public Service Colorado	1998	Defeated: 67% - 33%
Frankfort, IL	Commonwealth Edison	1998	Defeated: 86% - 14%

5.3 *Feasibility Study Limitations*

The impetus for considering a takeover varies among municipal governments, but often centers around issues such as upcoming franchise renewal negotiations, proposed utility rate increases, or service and reliability problems. One of the first steps taken by a city or county when considering a contested municipalization is to authorize a feasibility study.

With the completion of the Preliminary Feasibility Study, a municipal government must decide whether to proceed with its attempt to take over the incumbent utility’s distribution business. Consultants to those considering a takeover have consistently underestimated the cost and time involved in completing a contested municipalization attempt, one reason for the near 100 percent failure rate. In the case of Las Cruces, New Mexico, the consultant forecasted in 1991 that it would cost that city $13 to $26 million to acquire the system. In 1999 Las Cruces stopped its takeover effort after the price tag had escalated to over $105 million, as illustrated in the following graphic. Similarly, Winter Park, Florida, which recently completed a takeover, saw its takeover cost escalate from an original estimate of $16 million to nearly $50 million by the time the takeover was completed.

Figure 5-4. Las Cruces Takeover Case – Rising Costs.

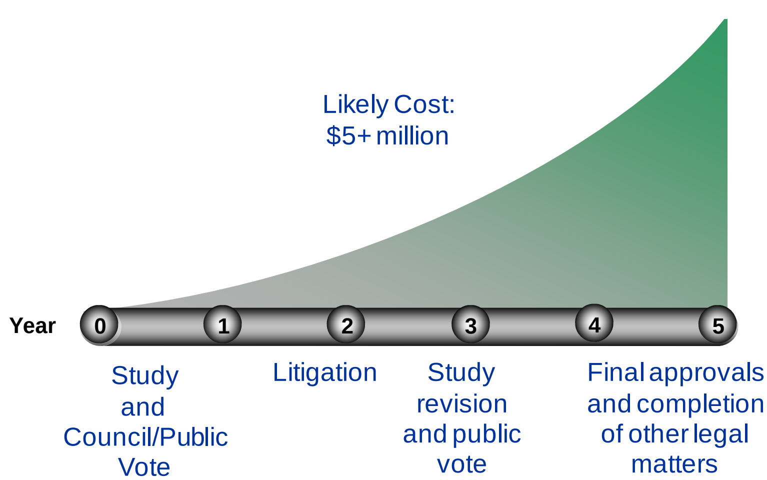


6.0 Conclusions and Recommendations

The result of the analysis in this report demonstrates the concept of the Jefferson County PUD taking over the electric business from PSE will lead to higher electric rates. Section 2.0 of the report forecasts the PUD will incur takeover costs conservatively estimated to be $77 million exclusive of other potential significant costs, such as stranded costs and severance damages, that would likely be incurred by the PUD. Section 3.0 demonstrates that the resulting PUD's cost structure could exceed 11.5 ¢/kWh, which exceeds PSE's forecasted electric rates of 9.8 ¢/kWh. Under the model presented in section 4.0, to avoid negative cash flows, the PUD would need to impose rates that are on average 19 percent higher than PSE's. In addition, since BPA power at Tier 1 rates is not expected to be available during the first 3 years of operation, customers could see rates 50 percent higher than PSE during those first 3 years should the PUD need to purchase power at market prices exceeding 8 ¢/kWh. Section 5.0 discusses the history of prior municipal takeover cases, demonstrating most existing electric municipal utilities were formed in the early 1900's and nearly all attempted contested takeovers of an existing utility business by a municipal government ended in failure.

Forming a new public electric utility by taking over an existing utility is a daunting challenge. The premium paid to acquire the system and lost economies-of-scale normally overweigh the few financial advantages a government entity may have, such as lower financing costs.

Figure 6-1. Representative investment over time to complete a takeover.



The community and legal ramifications are also a challenge. Normally such takeover attempts are a very divisive issue in the community and requires 4 to 8 years and millions of dollars of effort just to get through the study and litigation phases of the project. A typical timeline and steps involved in completing a takeover is illustrated in the following table.

Figure 6-2. Major takeover steps.

KEY STEPS	LENGTH OF TIME	COST RANGE ($ MILLION)
1. Initial Feasibility Study	Up to 6 months	\$0.1-\$0.3 million
2. PUD Council Vote/Public Vote		
3. Litigation to Determine Cost – includes performing a system inventory, hiring expert witnesses and consultants, preparing and presenting testimony	1 to 2 years	\$3-\$6 million
4. Revised Feasibility Study	Up to 3 months	\$0.1-\$0.3 million
5. Public Vote	3 to 6 months	\$0-\$0.5 million
6. Other Legal Challenges – appeals of ligation results (possibly to state supreme court), appeal of stranded cost to the Federal Energy Regulatory Commission (FERC), transmission access issues at FERC	1 to 3 years	\$1-\$6 million
7. Utility Startup– billing systems, call center, metering system, contracting for generation supply and distribution maintenance, distribution system separation, parts inventory established, key hires, bond issuance, etc.	1 to 2 years	Tens of millions

Note: cost estimate does not include other takeover costs such as cost to buy the business, separation costs, and city staff expenses.

It is UtiliPoint's experience that once a takeover process begins it can be very difficult for both parties to stop the process. Invariably the preliminary feasibility by the PUD's consultant raises the hope that taking over the electric utility business will be highly profitable. The reality is no viable business will be purchased at bargain basement prices. Once these real costs become apparent it can still be difficult to reverse course. UtiliPoint concludes that a takeover of the electric business in Jefferson County is unlikely to financially benefit the PUD and customers and therefore it is not in the public interest to pursue such an effort.