# San Joaquin Local Agency Formation Commission

Market Expert Report

May 21, 2010

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# *1. INTRODUCTION AND SUMMARY*

PA Consulting Group, Inc. (PA) was retained by the San Joaquin Local Agency Formation Commission (SJ LAFCo) to appraise the market value of Pacific Gas and Electric's (PG&E) distribution assets (the "Assets") located in San Joaquin County in and around the cities of Manteca, Ripon, and Escalon in California, and which the South San Joaquin Irrigation District (SSJID) proposes to acquire from PG&E through eminent domain. In addition, SJ LAFCo has retained PA to review and comment on each of the appraisal reports from SSJID and PG&E, as well as review and assess the viability of SSJID's business plan and ability to achieve a 15% reduction in rates.

## 1.1 OVERVIEW OF THIS REPORT

This report provides PA's opinion of value and describes the approach it used in forming that opinion. In addition, it provides PA's assessment of each of the appraisal reports issued by SSJID and PG&E and an opinion on the viability of SSJID's business plan.

This section provides an overview of PA's appraisal, and Section 2 presents salient facts and opinions. Section 3 describes the Assets, and Section 4 provides an overview of the appraisal methodology. Section 5 describes the valuation approaches and the results of the valuation. Section 6 provides PA's assessment of the two appraisal reports from SSJID and PG&E and Section 7 provides PA's assessment of SSJID's business plan. Section 8 provides the required Uniform Standards of Professional Appraisal Practice (USPAP) certification. Supporting information is presented in the appendices.

## 1.2 STATEMENT OF OBJECTIVES

This appraisal provides a valuation of the Assets as of December 31, 2010 (the "Effective Date"). This report represents a summary appraisal report, as defined by USPAP and as promulgated by the Appraisal Standards Board of the Appraisal Foundation. The analysis presented in this report does not evaluate the financial or lien structure of the Assets.

### 1.2.1 Purpose and intended use of this report

The purpose of this appraisal is to estimate the fair market value of the fee simple estate of the Assets as of the Effective Date. SJ LAFCo may use this appraisal for assessing the value of the Assets along with other appraisal reports and the viability of the SSJID business plan.

This report may not be used for any other purpose without the written consent of PA.

### 1.2.2 Definition/premise of value

This appraisal provides an opinion of the market value of the Assets. The market value of a given Property is defined in the USPAP developed by the Appraisal Standards Board of the Appraisal Foundation as:

> The most probable price which a Property should bring in a competitive and open market under all conditions requisite to a fair sale, the buyer and seller each acting prudently and knowledgeably, and assuming the price is not affected by undue stimulus. Implicit in this definition is the consummation of a sale as of a specified date and the passing of title from seller to buyer under conditions whereby:

1. Buyer and seller are typically motivated;
2. Both parties are well informed or well advised, and acting in what they consider their best interest;
3. A reasonable time is allowed for exposure to the open market;
4. Payment is made in terms of cash in United States dollars or in terms of financial arrangements comparable thereto; and
5. The price represents the normal consideration for the Property sold unaffected by special or creative financing or sales concessions granted by anyone associated with the sale.

In California in particular, the Fair Market Value definition when a government entity takes property by eminent domain is:

> The fair market value of the property taken is the highest price on the date of valuation that would be agreed to by a seller, being willing to sell but under no particular or urgent necessity for so doing, nor obliged to sell, and a buyer, being ready, willing, and able to buy but under no particular necessity for so doing, each dealing with the other with full knowledge of all the uses and purposes for which the property is reasonably adaptable and available. (Code Civ. Proc. § 1263.320 (a))
>
> The fair market value of property taken for which there is no relevant market is its value on the date of valuation as determined by any method of valuation that is just and equitable. (Code Civ. Proc. § 1263.320 (b))

## 1.3 DESCRIPTION OF THE ASSETS

All of the Assets are located in San Joaquin County in and around the cities of Manteca, Ripon, and Escalon in California (described in further detail in Section 2.1). An overview of distribution assets which SSJID proposes to acquire from PG&E is provided in Table 1-1.

| Table 1-1: Distribution Summary | |
|---|---|
| **Distribution Lines** | **Number of Miles** |
| Overhead | 585 circuit-miles |
| Underground | 215 circuit-miles |
| **Substations** | **Number of Stations** |
| Distribution | 2 |

## 1.4 SUMMARY OF VALUATION

PA's analysis is based on generally accepted valuation methods, including the Income Approach, the Market Approach, and the Cost Approach (described in Section 6). PA's conclusion of the value of the Assets that SSJID would need to compensate PG&E for, as of the Effective Date, is approximately $201 - $235 million, with a midpoint of $218 million, as presented in Table 1-2. In addition, PA concludes that SSJID would need to spend approximately an additional $19 million in severance costs, or capital upgrades, in order to successfully sever the system from PG&E. SSJID also estimates approximately an additional $30 million in its business plan[1] in other costs incurred. Therefore the total upfront cost to SSJID would be $249 - $283 million.

| Table 1-2: Value Summary | | | |
|---|---|---|---|
| **Asset** | **Low ($ million)** | **Mid ($million)** | **High ($million)** |
| Acquired Property | 171 | 188 | 205 |
| Severance Costs (PG&E) | 19 | 19 | 19 |
| Stranded Costs: Impairment | 5 | 5 | 5 |
| Other Damages | 6 | 6 | 6 |
| **Total** | **201** | **218** | **235** |

## 1.5 SUMMARY OF PA'S REVIEW OF APPRAISAL REPORTS

PA reviewed the Appraisal Report prepared for SSJID by R. W. Beck, dated August 2009 and the Distribution Network Inventory and Severance Issues Report prepared for SSJID by Siemens, dated May 2009 which the R.W. Beck report relied upon. We also review the Black & Veatch report titled Estimating the Fair Market Value of PG&E'S Retail Electric Utility Assets in the Area South San Joaquin Irrigation District Proposes to Serve, prepared for

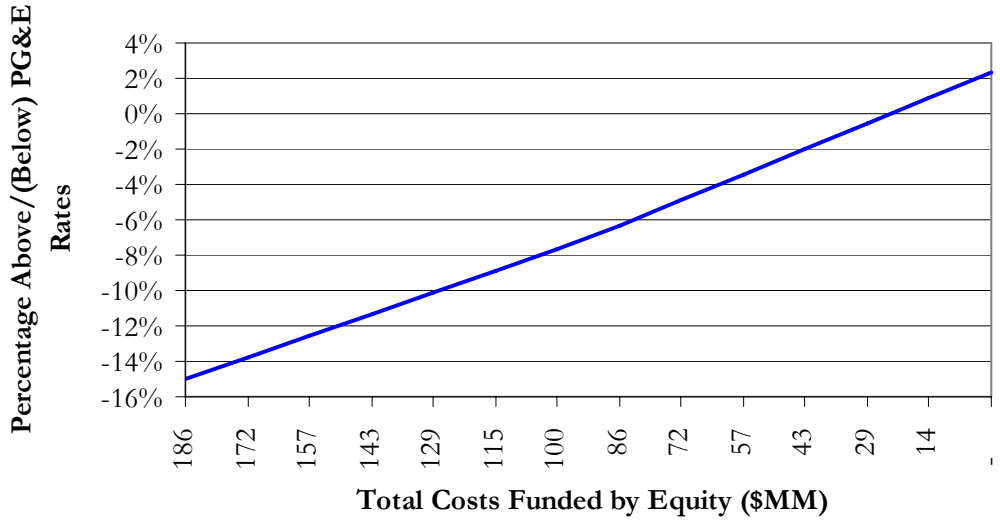
[1] SSJID has a total of additional costs above and beyond the price for the Assets and capital upgrades (severance costs) of approximately $42 million, but includes approximately $12 million of capital for repair and replacement which could be spent in years that it is incurred and therefore, PA only assesses approximately $30 million in total upfront cost incurred to SSJID.

PG&E and dated December 2009. An overview of PA's findings for each report is presented in Chapter 6. At a high level, PA finds that the income approach that R.W. Beck relies upon to determine value has flawed assumptions and therefore results in value lower than that which PA projects for the facilities. PA finds that the Replacement Cost New less Depreciation approach as well as the Going Concern value which the Black & Veatch report relies upon to determine value has flawed assumptions which result in value higher than that which PA projects for the facilities.

## 1.6 SUMMARY OF PA'S REVIEW OF THE SSJID BUSINESS PLAN

PA reviewed the business plan submitted by SSJID in relation to its application to provide electric service and its intended purchase of the PG&E distribution system. Because this business plan relied upon an assumption for PG&E rates and because more updated rates have been released by PG&E, PA updated this business plan for the most recent PG&E rates, as of March 2010. This caused the revenue assumption for SSJID to increase. However, PA found that the purchase price and the long term cost of power assumptions in the SSJID business plan were too low. PA tested the business plan by using PA's projection of purchase price and cost of power. Based on this, the model indicates SSJID would either need to provide more total cash upfront (equity) and/or raise rates above those assumed in the business plan. Figure 1-1 illustrates the results of this test. At one end, SSJID would not need to change the discount of 15% to the assumed PG&E rates but would need to bring a total of $186 million of upfront cash, compared to the assumption that it would be fully funded through debt in its current business plan. At the other end, it would not need to bring any additional cash but would need to charge rates of approximately 2% above assumed PG&E rates.

**Figure 1-1: Additional Equity and Discount in Rate Combinations using PA Forecasted Purchase Price and Cost of Power in SSJID business plan updated for March 2010 PG&E Rates**



## *2. SALIENT FACTS AND OPINIONS*

The following are the salient facts and opinions that are presented in this report.

### 2.1 CURRENT OWNER

Pacific Gas and Electric

### 2.2 CLIENT AND OTHER INTENDED USERS

San Joaquin Local Agency Formation Commission

### 2.3 EFFECTIVE VALUATION DATE

This appraisal reflects the values as of December 31, 2010.

### 2.4 OPINIONS

#### 2.4.1 Assumptions and limiting conditions

This appraisal is dependent on the assumptions stated in this report. In addition, PA has assumed the following:

- there are no liens associated with the Assets.
- there are no new technological breakthroughs in terms of distribution technology.

#### 2.4.2 Marketing time

Marketing time is the amount of time it might take to sell a property interest at the concluded market value level during the period immediately after the effective date of an appraisal. PA believes a reasonable marketing time for the Assets is one to two years, which is typical for these types of facilities in the electric industry.

# 3. OVERVIEW OF THE ASSETS

## 3.1 PROPERTY DESCRIPTION – POWER DISTRIBUTION FACILITIES

The subject PG&E distribution assets include distribution lines and distribution substations, all located in San Joaquin County within the service territory of South San Joaquin Irrigation District. The distribution assets are 100% owned by PG&E. The substation distribution facilities have in-service dates from 1962 to 1997. Most of the overhead distribution lines and associated equipment were installed during the same period, with some new construction and replacements continuing into 2010. Table 3-1 provides an overview of the distribution system.

**Table 3-1: Distribution Summary**

| Distribution Lines | Number of Miles |
|---|---|
| Overhead | 585 circuit-miles |
| Underground | 215 circuit-miles |
| **Substations** | **Number of Stations** |
| Distribution | 2 |

PA visited the substations and a representative sample of distribution lines throughout the SSJID service area. The distribution substations were inspected from outside the fence. PA observed distribution lines that were near the substations and in selected areas close up, and observed others from a distance during drives throughout the area. No pad-mount or subsurface enclosures were opened. PA found that substation conditions are typical for their age. Some of the older overhead distribution lines show extensive erosion of the pole material (wood), and a significant number of poles with ground-line reinforcement (either steel or wood) were noted. Also, an unusually high number of significantly out-of-plumb poles were noted. One oil circuit breaker is still in use in the Ripon Substation, but all others have been replaced with lower-maintenance vacuum circuit breakers. Substation layout provides ample space for maintenance. Space available for expansion is sufficient for SSJID's expansion plans.

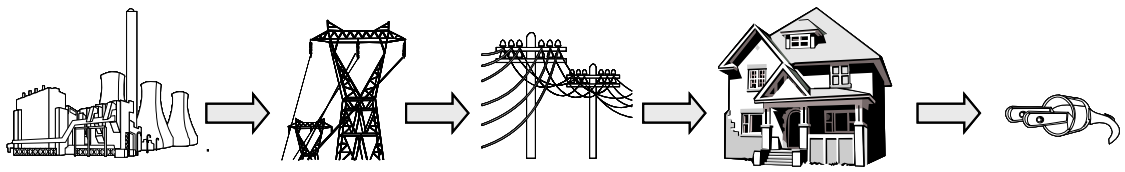
## 3.2 FUNCTIONAL OVERVIEW – POWER DISTRIBUTION FACILITIES

### 3.2.1 Electricity industry background

The production and delivery of electricity to end users is a complex process, but in simplified form it can be decomposed into the distinct segments shown in Figure 3-1.

Electricity is first generated at a power plant that may use one of several fuels (generally, natural gas, nuclear energy, coal, water, wind, or solar). The electricity is then transmitted via an integrated network of high voltage transmission lines to locations where it is needed. The voltage is then reduced, the electricity is transmitted through a distribution network to end users (residential, commercial, and industrial customers), and customer usage is metered.

**Figure 3-1: Process of Electricity Production and Delivery**




### 3.2.2 Distribution Network

The distribution network includes substations, distribution lines, transformers, and customer service drops.

*Distribution substations* convert the electricity from "high voltage," above 50,000 volts, to "medium voltage," between 4,000 and 35,000 volts.[2] In addition, the substations provide switching and control functions.

*Distribution feeders* are the lines which carry electric power from the substation to the customer location. The feeders may be overhead, using wires attached to poles by insulators, or underground, consisting of insulated cables usually run in conduits. From one to twelve or more feeders may be connected to one substation. Each feeder typically serves from a few hundred to a few thousand customers. The feeders often include switching equipment, voltage regulators, capacitors (which help to control voltage as well as increase the efficiency of the distribution system), and fault-protective devices (fuses and automatic switches which isolate a section of the feeder when a short circuit or large overload occurs, thus preventing damage and allowing the rest of the system to continue operating normally).

*Distribution transformers* convert the medium voltage electricity to "low voltage," usually between 120 and 480 volts, for use by the customers. On overhead feeders, the transformers are mounted on the poles that support the wires. On underground feeders, they may be in subsurface vaults or, more commonly, in above-ground metal enclosures.

[2] Electric utility voltages are commonly expressed in kilovolts, or thousands of volts, abbreviated kV.

*Service drops* (or simply "services") connect the low voltage side of the distribution transformer to the customer premises, where a *meter* records the amount of electricity used for billing purposes.

### 3.2.3 Distribution Utility Operations

A distribution utility installs, maintains, and operates the distribution system described above to provide electric power to its customers. It also procures power (by purchase or self-owned generation) and arranges for that power to be transmitted over the transmission network to its distribution substations. And, it provides customer-oriented services including connections and disconnections, billing, and outage response.

Distribution utilities are considered to be "natural monopolies," because it is not very cost-effective to have competing systems of substations and feeders serving the same area.[3] As a result, some sort of regulation is imposed to protect customers from unreasonable prices or service. For investor-owned utilities in California, the regulating authority is the California Public Utilities Commission (CPUC). The CPUC makes rules regarding the reliability of electric service as well as the rates that can be charged. For publicly-owned utilities, regulation takes the form of oversight by elected officials. If the utility does not provide adequate service or fair rates, the customers can use the ballot box to affect change. While the CPUC does not directly regulate publicly-owned utilities, the standards and rates set by the CPUC become de facto standards since poorer service or higher rates would lead the voters to demand improvements.

The rates set by the CPUC allow a regulated utility to recover all of its "prudently-incurred" expenses and to earn a fixed rate of return on its investments in facilities (capital costs). The rate of return is selected to allow the utility to attract necessary capital. The cost of power (purchased or self-generated) and of transmission is included in the total rate paid by the customer. In fact, distribution accounts for only about 28% of the average electric bill.[4]

[3] There are some places where competition exists between distribution utilities, but these are not very common because of the economic inefficiency.

[4] From *Regulated California Electric and Gas Utility Ratepayer Costs*, CPUC, February 2008

# *4. APPRAISAL METHODOLOGY*

## 4.1 VALUATION METHODS

The studies and analyses that PA has undertaken with respect to the expected market value of the Assets were based on generally accepted valuation methods, including the Income Approach, the Cost Approach, and the Market Approach. The Income Approach, or discounted cash flow (DCF) analysis, estimates the net present value of net income that the property is projected to earn. The Cost Approach considers various cost methods such as the Original Cost Method, which is the original cost to construct the property, and the Replacement Cost Method, which is an estimate of the cost to build a new project similar to the property with requisite technological and economic modifications. Finally, the Market Approach, or comparable sales method, assesses value based on recent fair market sales of similar facilities under similar circumstances.

## 4.2 HIGHEST AND BEST USE

The Assets contain extensive capital improvements in place that enable distribution of electricity. Use of the Assets for other uses, such as residential development, would entail first removing the current capital improvements and then constructing different capital improvements. These costs reduce the value of the Assets for other uses, relative to vacant land.

For these reasons, the highest and best use of the Assets is the current use, the distribution of electricity.

## 4.3 SOURCES OF INFORMATION

PA's opinions set forth herein are based on information provided by PG&E, SSJID, other information generally available to PA, and studies and analyses undertaken by PA, all of which are basic to and in support of our opinions with respect to the market value of the Assets. The documents relied upon include:

**PG&E Sources:**

- Estimating the Fair Market Value of PG&E'S Retail Electric Utility Assets in the Area South San Joaquin Irrigation District Proposes to Serve, Black & Veatch, December 2009
- Valuation Study of PG&E Facilities and Infrastructure, Communities of Manteca, Ripon and Escalon, PG&E/Global Energy, May 2, 2005
- PG&E FERC Form 1, 2008
- Memo re: Applicable Standards for Appraisal of PG&E's Property; Evaluation of SSJID ' s Appraisal Report; Expected Cost to SSJID for Taking PG&E's Property, Manatt, Phelps & Phillips, LLP, October 26, 2009
- City of Manteca Electric Franchise Ordinance, March 5, 1956
- City of Ripon Electric Franchise Ordinance, January 15, 1946
- City of Escalon Electric Franchise Ordinance, July 1, 1957

- County of San Joaquin Electric Franchise Ordinance, March 30, 1965
- Equipment summaries, SSJID service area, PG&E (confidential)
- Severance plan, SSJID service area, PG&E (confidential)
- Manteca Substation M&R One Line Diagram, PG&E
- Manteca Substation General Arrangement Drawings, PG&E
- Ripon Substation M&R One Line Diagram, PG&E
- Ripon Substation General Arrangement Drawings, PG&E
- Advice Letter 3603-E-A, February 25, 2010
- PG&E Corp 2009 Form 10-K, filed February 29, 2010
- South San Joaquin Irrigation District, Power Supply Analysis, Black and Veatch, March 19, 2010
- SSJID –Hourly Load Profile -3-23-10

**SSJID Sources:**

- SSJID Application to San Joaquin LAFCo, September 2009
- Market Expert Report, Siemens, May 2009
- Appraisal, Electric Distribution System Facilities, R. W. Beck, August 2009
- SSJID Microsoft Excel Business Plan Model
- SSJD response to power supply issues
- Discussion with Shell Energy North America

**PA Sources:**

- PA's market price forecast models

**Other Sources:**

- CostWorks, v. 14.02, 2010 Heavy Construction, R. S. Means
- Handy-Whitman Index of Public Utility Construction Costs, Bulletin No. 168
- Department of the Treasury Internal Revenue Service Publication 946
- California Energy Commission California Energy Demand 2010-2020 Adopted Forecast Commission Report and Adopted Demand Forecast Forms, December 2009
- California ISO GMC Rates for 2004-2010, Effective 4/1/2010. Bloomberg, LP
- Bloomberg, LP
- Tax Foundation
- Federation of Tax Administrators

- Blue Chip Economic Indicators, January 10, 2010
- Public Utilities Fortnightly Annual ROE Survey, November 2009
- Global Insight 30-year U.S. and Regional Economic Projections, May 2009

# 5. MARKET VALUE SUMMARY

PA considers three approaches as promulgated by USPAP: In addition to the value of the Assets themselves, SSJID will need to compensate PG&E for severance, stranded costs and other costs as described below.

- income
- cost
- market

Each of these approaches is discussed below:

## 5.1 INCOME APPROACH

The Income Approach considers the revenue and cost projections associated with the property of interest. Discount rates are utilized to discount the revenue and cost projections back to the appraisal date. Under the Income Approach, the value of the property of interest is equal to the net present value of forecasted un-levered free cash flows through the useful life of the asset. PA has derived an Income Approach value from both the perspective of a municipal and regulated utility purchaser, as these are the two types of possible buyers for the facilities.

### 5.1.1 Key assumptions

Key assumptions to PA's Income Approach analysis are as follows:

- ***Discount rate:*** For its Income Approach analysis, PA applied a range of Weighted Average Cost of Capital (WACC) discount rates to its un-levered free cash flows. From the perspective of a municipal purchaser, PA applied a range of 7% to 8%, yielding a mid-point of 7.5%. From the perspective of a regulated utility purchaser, PA applied a range of 7% to 9%, yielding a mid-point of 8%. The range PA utilized was derived through analysis of market, industry and company specific data and risks. Market data as of March 31, 2010 was utilized.

- ***Study period:*** PA applied equipment life assumptions to derive a remaining useful life for the Assets. In this regard, PA has assumed a remaining useful life of 35 years for the Assets, provided the system is properly maintained.

- ***Revenue:*** Distribution revenues have been forecasted based on projected energy sales multiplied by forecasted distribution rates. Energy sales were assumed equal to those forecasted in SSJID's business plan model for 2011, and were escalated based on California Energy Commission (CEC) forecasted energy growth rates thereafter. Base level distribution rates were based on PG&E's March 1, 2010 distribution rates, and were escalated at an assumed inflation rate of 1.8%. Details regarding the energy sales and distribution rates are presented in Appendix B.

- ***O&M and A&G:*** Operations and maintenance (O&M) and administrative and general (A&G) expenses were derived on a bottom-up basis, based on expected staffing levels for the distribution system. O&M and A&G expenses were escalated at an assumed inflation rate of 1.8%.

- ***Public Benefit:*** Public benefit costs were assumed at 2% of total cost of service.
- ***Franchise Fee and Property Tax:*** Franchise fees and property taxes were assumed at 2% of total cost of service. While municipal purchasers are tax-exempt entity's, PA included these expenses in its municipal purchaser analysis due to the likelihood that a tax-exempt purchaser would be required to provide payments in lieu of taxes to gain local approval of the sale.
- ***Nonbypassable payments:*** Nonbypassable payments were assumed equal to those forecasted in the SSJID business plan model.
- ***Capital expenditures:*** Capital expenditures were based on PA's estimate for repair and replacement required to maintain the Assets for the remainder of the 35 year useful life.
- ***Income tax:*** PA's Income Approach analysis from the perspective of a municipal purchaser included no income tax payments, as a result of this purchaser group being tax-exempt. However, in its Income Approach analysis from the perspective of a regulated utility purchaser, PA forecasted income taxes assuming an arms-length asset sale transaction. 20-year Modified Accelerated Cost Recovery System (MACRS) tax depreciation was applied to the Assets. The tax basis was set at derived Income Approach valuations and adjusted periodically by forecasted capitalized expenditures. A statutory federal corporate tax rate of 35% and statutory California corporate state tax rate of 8.84% was applied.

### 5.1.2 Income approach results

The Income Approach yields estimates of value for the Assets as demonstrated in Table 5-1. Detailed pro forma's are presented in Appendix C.

**Table 5-1: Summary of Income Approach**

| | Low ($ million) | Mid ($ million) | High ($ million) |
|---|---|---|---|
| Municipal | $176 | $190 | $205 |
| Regulated Utility | $87 | $105 | $127 |

## 5.2 COST APPROACH

The cost approach is based on a calculation of the cost of the facilities that are the subject of the transaction. The calculated cost is then adjusted for various factors that reflect the actual value to by buyer and seller.

### 5.2.1 Overview

The cost approach PA has undertaken in this analysis is based on replacement cost analysis. Other cost approaches such as original cost or original cost trended less depreciation do not generally represent the current value of electric system assets and are not commonly used for valuation purposes.

Replacement cost can be calculated based on either exact duplication of the existing facilities (Reproduction Cost New) or on a functionally equivalent replacement using current technology and practices (Replacement Cost New). Replacement Cost New is the universally accepted cost approach for electric system facilities, and PA has used this method.

### 5.2.2 Replacement cost less depreciation

The Replacement Cost analysis involves estimating the "overnight" cost to construct a new facility having the same usefulness as an existing one. In this approach it is postulated that a functionally equivalent system is constructed using present-day materials and techniques under present-day conditions. The cost to construct a new facility is then adjusted for one or more of the following; physical deterioration, functional obsolescence, and economic obsolescence. Physical deterioration is the loss in value caused by wear and tear. Functional obsolescence reflects loss in usefulness, which could be due to outmoded equipment. Economic (or external) obsolescence reflects the loss in value or usefulness of a property caused by factors external to the property, such as increased competition.

PA compared the inventory used by Black & Veatch for its Appraisal Report for PG&E, and that developed by Siemens for SSJID. We found that the differences are negligible, so we used the PG&E inventory as the basis for RCN.

RCN values were based on publically available cost data, proprietary PA data, and PA's experience and judgment. All values were adjusted for the northern California market in which the Assets are located (typically Modesto/Stockton where adjustments for that specific area were available) and for brownfield[5] construction under the conditions observed in the field.

PA determined the average age of the various distribution system components based on PG&E records, confirmed by field observations. In general, we used PG&E's average service life estimates as given by Black & Veatch in Table 4.3.2; however, some of the average life estimates are shorter than our experience indicates, notably poles, overhead conductors and equipment, and street lights. The average life and average age PA utilized are shown in Table 5-2.

[5] Brownfield construction is defined as construction in the presence of existing improvements and infrastructure (such as houses, streets, businesses, and other utilities). In contrast, Greenfield construction is defined as construction in the absence of any improvements or infrastructure. Because of the necessity to work around and sometimes disturb and restore these improvements, brownfield construction is typically more expensive than Greenfield construction as it pertains to distribution assets.

| Table 5-2: Average Service Life and Average Age – Distribution Assets | | |
|---|---|---|
| | **Average Service Life (Years)** | **Average Age (Years)** |
| Substation Equipment | 43 | 28 |
| Wood Poles | 45 | 38 |
| Overhead Conductor | 45 | 38 |
| Underground Conduit | 63 | 14 |
| Underground Cable | 44 | 14 |
| Overhead Transformers | 32 | 24 |
| Overhead Switches | 38 | 24 |
| Overhead Capacitor Banks | 38 | 24 |
| Underground Transformers | 32 | 18 |
| Padmount Switches | 38 | 24 |
| Meters | 32 | 21 |
| Overhead Services | 32 | 21 |
| Underground Services | 63 | 14 |
| Street Lights | 25 | 14 |

Straight-line depreciation was used to determine the depreciated value of the distribution system. While PG&E argues for "present-worth" depreciation, in our experience and judgment straight-line depreciation is preferred. The goal is to determine the actual value of the system as it exists today. The market for used equipment generally shows initial depreciation rates even greater than straight-line, and as we discuss in our assessment of the Black & Veatch Appraisal Report, we find the arguments for present-worth depreciation unpersuasive. The present-worth method always results in higher asset value (lower depreciation) than straight-line depreciation except when new or at end-of-life, when they are equal.

PA did not appraise the value of land, land rights or easements. Because the appraisal was more current, we incorporated the value per acre for substation land of PG&E's Appraisal Report prepared by FTI Consulting and attached to the Black & Veatch Appraisal Report.

PG&E reports private easements on 63.04 linear miles for transmission and distribution purposes, totaling more than 144 acres. There are also other easements for which PG&E has not been able to identify the dimensions or other data. The FTI appraisal valued these easements at $15 to $18 million. Assuming that the easements represent an average of 62.5 percent of the value of the land, this represents an average value of about $183,000 per acre. We have not received complete data from PG&E detailing where these easements lie, so we cannot definitively say that the value is high; but we would expect more of the easements to be in relatively rural areas (where public street right-of-way is not available) where land values tend to be lower. Furthermore, some of these easements are used for transmission lines with underbuilt distribution. SSJID would not acquire transmission line right-of-way,

although some portion of the easement value might be assigned to them in the event of an under built distribution line. Finally, some of the easements are not currently in use, and others may not represent the most economical route were the system to be built today. In an RCN calculation, we would use the most economical route under today's conditions. Pending more definitive information, we have used an average land value of $125,000 per acre, with an easement value of 50% of the land value.

Plottage value reflects the cost of assembling a collection of land rights to form an integrated whole distribution system. We applied a plottage factor of 1.15 to the substation parcels and 2.0 to the line easements. We note that the percentage cost of acquiring a large tract of land is much lower than that of acquiring many small parcels under similar circumstances; hence, we use a different plottage factor for the substation sites.

Table 5-3 presents the Replacement Cost less depreciation analysis for the distribution assets. The derived value of the Assets under the replacement cost less depreciation is $170.8 million.

**Table 5-3: Summary of Replacement Costs**

| | Replacement Cost New ($ million) | Replacement Cost less Depreciation ($ million) |
|---|---|---|
| Distribution Substations | 13.3 | 4.6 |
| Distribution Lines and Equipment | 277.8 | 140.2 |
| Land – Substations | 3.5 | 3.5 |
| Right-of-Way Easements | 22.5 | 22.5 |
| Total | 317.1 | 170.8 |

## 5.3 MARKET APPROACH

### 5.3.1 Overview

The market approach involves the use of data from sales of similar property, with reconciliation of differences among the property sold and the property being valued. This approach requires an active market for comparable property, meaning a market in which sales of similar assets take place on a regular basis.

Distribution asset values are very region specific and are dependent on several variables, including but not limited to:

- regional location
- age of the units and components
- O&M costs

- required capital expenditures

Information on a number of these issues is typically not publicly available in the comparable sales data. In addition to this, distribution assets generally include assets and intangibles beyond distribution assets. For these reasons, PA was unable to derive comparable sales for the Assets.

## 5.4 SEVERANCE COSTS

The PG&E distribution system has been developed and is operated as an integrated whole. In order for SSJID to serve the customers within its service territory, utilizing the elements of the distribution system acquired from PG&E, and for PG&E to continue serving the remaining customers, it is necessary to separate the system functionally, and preferably physically as well. Severance value is the cost to both parties to carry out this separation.

There are many factors that determine the most cost-effective plan of severance that provides each party a safe and reliable distribution system. Both SSJID and PG&E have developed severance plans. PA reviewed the system along the boundary of SSJID's service territory, and identified general severance requirements. We then reviewed the SSJID and PG&E severance plans, and where one or both identified solutions appear to be reasonable, we adopted them. In particular, we used SSJID's plan to construct a new substation ("Jack Tone Substation") and both parties' suggestion of double circuit distribution lines on shared poles along parts of the boundary.

While SSJID's consultant performed quite detailed feeder studies within the SSJID boundaries, we did not have access to similar studies covering all the impacted areas outside of those boundaries. We attempted to provide both continuity of circuits and maintain existing switching and backup flexibility. We believe our severance value is a good indicative value, although we recognize there could be a more optimum solution. It will be necessary for SSJID and PG&E to work together to refine and finalize the severance plan. If the parties work together in good faith to optimize the plan, we expect that they will find some areas where additional construction at higher cost is required, but also areas where less new construction is required with resulting decreased cost.

We did not adopt SSJID's position that, without any action on the part of the customers, PG&E, or the entity that would ultimately serve the affected customers, SSJID can acquire through eminent domain PG&E facilities located outside of its territory and not needed to serve loads within its territory. Thus we assumed that all customers outside of the SSJID boundaries now served by PG&E would continue to be served by PG&E. We agree that the severance plan would be simpler and less expensive if some of those customers were served by Modesto Irrigation District as postulated by SSJID's severance plan, but evaluation of the legal authority to do so is outside of our scope.

We accepted PG&E's position that it will need two new small substations just west of the SSJID territory to provide backup service comparable to the existing system. Further study might show that construction of new feeders and/or upgrading existing feeders could be a more economical solution than one or both of these substations, although PA estimates that it would likely only be within $1-3 million of its current estimation for new substations.

Severance costs will be incurred by both the seller and the buyer. In this case, with a substantial part of the severance being double-circuit lines to be constructed by one party and used by both parties, the amount of construction and thus the amount of the severance cost assignable to each party is difficult to determine; however, the cost responsibility for both lies with the buyer. We have therefore assigned half of the distribution system severance costs to each party. Table 5-4 presents the severance cost summary.

**Table 5-4: Summary of Severance Costs**

| | PG&E Costs ($ million) | SSJID Costs ($ million) | Total Costs ($ million) |
|---|---|---|---|
| Manteca Substation | 0.95 | 0.94 | 1.90 |
| Ripon Substation | | 2.25 | 2.25 |
| Jack Tone Substation | | 5.87 | 5.87 |
| Lathrop Substation | 2.72 | | 2.72 |
| South of Vierra Substation | 2.72 | | 2.72 |
| Electric Distribution | 8.79 | 8.79 | 17.57 |
| Land | 3.63 | 0.71 | 4.34 |
| Total | 18.80 | 18.57 | 37.37 |

## 5.5 STRANDED COSTS

In addition to the severance costs, there will be some PG&E facilities which are no longer utilized fully because of the transfer of load to SSJID facilities. The most significant of these are three substations: Avena, Vierra, and Riverbank. We have relied upon the age and condition assessment as well as the initial load transfer given in the Siemens inventory report, but since the Avena substation is at end of life according to the PG&E lifetime assumptions, we have used a longer assumed lifetime of 52 years, based on the Iowa Curves method[6]. A person who has reached the age of 75 has a greater life expectancy than one who is only 55 years old; in the same way, equipment which has reached the average life expectancy is expected to remain useful for some additional time. While the percentage impairment would be expected to decrease over time because of load growth within the remaining PG&E area, the rate of decrease is small and, when discounted to reflect present value, the effect on total impairment damages is insignificant. We have also estimated RCN for all three substations based on the calculated RCN of Manteca and Ripon Substations. This gives a stranded cost estimate of $4.24 million as shown in Table 5-5.

[6] The Iowa Curves provide a method to estimate the probable remaining life of equipment when it has reached a given age or percentage of average life. A discussion of this method is included in the Black & Veatch report, Appendix E.

| Table 5-5: Stranded Costs - Substations | | | |
|---|---|---|---|
| | **Est. RCNLD ($ million)** | **Impairment (%)** | **Impairment ($ million)** |
| Vierra | 6.84 | 38.3 | 2.62 |
| Avena | 0.21 | 71.4 | 0.15 |
| Riverbank | 3.75 | 39.3 | 1.47 |
| TOTAL | 10.80 | | 4.24 |

In addition to the substations, there will be some reduced usage of distribution lines. This is extremely difficult to calculate, requiring a detailed before-and-after distribution study with numerous assumptions which make it quite speculative. Black & Veatch indicated that an estimate of other stranded costs would be provided at a later date. Siemens listed a few small sections of line they indicated would be impaired, but did not offer an estimate. We include $0.5 million in recognition that some impairment of distribution lines is expected.

## 5.6 OTHER VALUE

There are several types of assets and liabilities that do not fit neatly into the severance and stranded cost categories. We have grouped these under the heading of “Other Value” for convenience.

### 5.6.1 Other Assets

The “Other Assets” include Accounts Receivable, unbilled revenues, and Construction Work In Progress (CWIP). These amounts must be reconciled as of the date of transfer, since they will be fluid up to that point. As an indicative value, we have used the amounts provided by PG&E in the Black & Veatch report. The estimated total value of the “Other Assets” is $13.5 million.

### 5.6.2 Other Liabilities

The only item included in “Other Liabilities” of which we are aware is negative salvage value. The usual calculation of net salvage value is based upon a historical average of actual salvage value received from the sale of removed and retired equipment less the cost of removal. For electric distribution equipment, the value is usually negative, representing a liability. This calculation when applied to equipment to be retired in the future is necessarily speculative, since while the labor associated with removal is predictable, the market for the removed materials is subject to fairly large excursions over a long period of time (the remaining life of the equipment). Thus it is customary to use the historical data from a somewhat arbitrary period to estimate the percentage of original cost that will be recovered (or expended) at retirement. Present value of the net salvage value is then calculated over the remaining life of the equipment.

We requested original cost data from PG&E and were told that it was not available. We could use construction cost indices to estimate original cost from our calculated replacement cost new, but this introduces yet another significant uncertainty into the calculation. After reviewing the data included in the Black & Veatch report, we have chosen to use their value as the best available estimate of net salvage value. The estimated total value of net salvage is negative $7.21 million.

## 5.7 RECONCILIATION OF VALUE

Based on the analysis presented herein, PA has developed an opinion of value taking into consideration the three methods of value. Table 5-6 presents a summary of the three methods. PA's conclusion is that the value of the Assets, as of the Effective date is approximately $201 - $235 million, including severance, stranded and other costs. This is based on a range of the RCNLD value to the high end of the income approach. PA's low end of the income approach is based on a regulated utility buyer and because municipal buyers do exist and in this case is the proposed buyer, the municipal buyer range is more appropriate for use in the conclusion. In addition to the fair market value derived for purchase of the Assets, PA also estimates that SSJID would need to spend approximately an additional $19 million in capital upgrades, or severance costs, on its own behalf and SSJID estimates approximately an additional $30 million in other upfront costs[7]. Therefore the total upfront cost to SSJID would be approximately $250 - $284 million.

**Table 5-6: Value Approach Summary**

| Asset | Income Approach ($million) | Cost Approach ($ million) | Market Approach ($ million) |
|---|---|---|---|
| | | RCNLD | |
| Distribution System | 87-205 | 171 | N/A |
| Severance Costs | 19 | 19 | N/A |
| Stranded Costs | 5 | 5 | N/A |
| Other Costs | 6 | 6 | N/A |
| Total | 117-235 | 201 | N/A |

[7] SSJID has a total of additional costs above and beyond price for the Assets and capital upgrades (severance costs) of approximately $42 million, but includes approximately $12 M of capital for repair and replacement which could be spent in years that it is incurred and therefore, PA only assesses approximately $30 million in total upfront cost incurred to SSJID.

# *6. ASSESSMENT OF THE APPRAISAL REPORTS*

## 6.1 ASSESSMENT OF THE SSJID APPRAISAL REPORT

PA has reviewed the Appraisal Report prepared for SSJID by R. W. Beck, dated August 2009. The Report presents a complete appraisal of the subject properties together with severance and stranded costs. The appraisal is based in large part on the Distribution Network Inventory and Severance Issues Report prepared for SSJID by Siemens, dated May 2009, which we have also reviewed.

Because the inventory prepared by Siemens has only insignificant differences from the PG&E inventory, and based on its internal evidence, we conclude that it is accurate and complete as of the date it was completed. Distribution system study results also appear to be accurate. We have the following comments on the Siemens report.

- The distribution feeder studies cover the feeders to be taken by SSJID, but do not cover the affected feeders to be retained by PG&E. While for the most part those feeders will be shorter and/or more lightly loaded than they are now, some portions will carry additional load and will have different backup arrangements. These feeders should be studied under the proposed severance plan.

- In our opinion, the severance plan for the Manteca Substation does not adequately consider the reliability of the transmission portion of the substation. While the plan makes a point of avoiding a brief interruption to an unfaulted transformer while clearing a faulted transformer, it imposes additional exposure on PG&E by converting the ring bus to an expanded double ring. At the same time it exposes SSJID to a complete, lengthy outage of all four transformers under a single breaker failure condition. SSJID's consultants should work with PG&E to develop a mutually agreeable arrangement. We believe this can be accomplished without an increase in severance cost or expansion of the area utilized.

- In our opinion, the proposed high-side arrangement for the Jack Tone Substation does not provide optimum reliability for the line to Ripon Substation. A full 5-position ring bus would be preferable. SSJID's consultants should work with PG&E to develop a mutually agreeable arrangement. We believe this can be accomplished without a significant increase in severance cost or expansion of the area utilized.

- As mentioned in our discussion of severance costs above, we are not convinced that SSJID can acquire through eminent domain PG&E facilities located outside of its territory and not needed to serve loads within its territory without any action on the part of the affected customers, PG&E, or the third party that would ultimately serve the affected customers. Thus in our opinion the severance plan must include facilities for PG&E to continue to serve all customers which it presently serves outside of the SSJID boundaries. We agree that the severance plan would be simpler and less expensive if some customers outside of the SSJID area were served by Modesto Irrigation District as postulated by SSJID's severance plan, but evaluation of the legal authority or the process to do so is outside of our scope.

- There are several instances where it is suggested that medium voltage (distribution primary) metering be used between sections of distribution line which would then be owned by different entities. This is technically acceptable but will result in additional coordination requirements between the owners, and possibly could compromise safety as a result. In addition, it requires one utility to subject its customers to service over another utility's system over which it has no control. It would be preferable to avoid such arrangements.

- There are also instances where low voltage metering is proposed to allow serving the customers of one utility from the system owned and operated by another utility. While this does not have the coordination and safety issues of medium-voltage metering, it still requires a utility to subject its customers to service over another utility's system, and should be avoided unless both affected utilities agree to it.

With respect to the R. W. Beck Appraisal report, we have the following comments.

**Cost Approach**

- The OCLD (rate base) calculation has no relevance to a prospective purchase; it deals with the status quo. In our opinion it should be omitted.

- Compared to PA's estimates, R. W. Beck consistently calculates lower RCN values. We assume a significant part of this difference is the use of greenfield rather than brownfield construction.[8]

- The value of land included in the appraisal was based on 2006 value. This should be updated. The assumption that land value has not changed is unsubstantiated.

- R. W. Beck was unable to evaluate the value of the easements due to lack of detailed information from PG&E. To complete their appraisal, it will be necessary to obtain this information. The actual value of the easements is much more significant than indicated in the R.W. Beck report.

- The estimate of net salvage value was calculated on RCN cost, while the historical data on which it was based used original cost. This results in a disconnect between the actual data and the calculated value, which in usual circumstances will overestimate the net salvage value whether positive or negative.

**Income Approach**

- There are multiple issues with the income approach, which R.W. Beck ultimately relied upon in their conclusion of value. PA has provided its analysis of what the appropriate income value is in Section 5-1. Some of the more significant issues with R.W. Beck's approach are detailed below:

[8] For an explanation of this difference, see footnote 5 in Section 5.2.2.

1. Revenues: The forecasted revenues R.W. Beck has derived are lower than those projected by PA. This is mostly due to the fact that the distribution rates that Beck is using are outdated as they are from PG&E 2007 General Rate Case. The distribution rates PA uses are from March 2010.

2. Taxes: R.W. Beck is including an assumption that the buyer is paying taxes where in fact there are buyers out there, including SSJID, which are not subject to income, property, and other taxes and therefore it is unreasonable to not also examine the value with a tax exempt entity. This is a significant value driver. If R.W. Beck were to exclude taxes from its analysis, its value would go from $60.5 million to $119.6 million.

3. Growth Rate: R.W. Beck uses a growth rate of 2.1% to derive its terminal value whereas the growth rate of the net cash flows from 2009 to 2020 range from 7-9%. This would imply that the cash flows at the end of ten years are still growing at faster than the assumed long term growth rate and therefore a terminal value after 10 years is inappropriate.

4. Discount Rate: R.W Beck uses PG&E's weighted average cost of capital of 8.79%. PG&E is the seller and not the buyer. It is more appropriate to look at the likely buyer's weighted average cost of capital. PA calculates that a municipal buyer's weighted average cost of capital is 7-8%. Using a discount rate of 7.5% would result in a value increase of approximately $13 million.

## 6.2 ASSESSMENT OF THE PG&E APPRAISAL REPORT

PA has reviewed the Black & Veatch report titled Estimating the Fair Market Value of PG&E'S Retail Electric Utility Assets in the Area South San Joaquin Irrigation District Proposes to Serve, prepared for PG&E and dated December 2009. The Report presents a complete appraisal of the subject properties together with severance and stranded costs. The report relies heavily on data provided by PG&E.

We have the following comments on the Black & Veatch report:

- Compared to PA's estimates, Black & Veatch consistently calculates higher RCN values. We have not been able to identify a reason for this difference. In the one area where we have data to compare, substation transformer costs, our numbers are similar to those used by PG&E.

- Black & Veatch uses, and attempts to justify the use of, "present worth" depreciation rather than straight-line depreciation. In our experience, straight-line depreciation is much more commonly used for utility RCNLD calculations. Black & Veatch argues that the value of the property is "the benefit that property provides to the owner," and gives an example of the "benefit" that a pole provides over varying periods. This is a variant of the income approach to value, which Black & Veatch has rejected in its report. Market value may or may not correspond to this value. For example, in the used utility equipment market, our experience is that the market value is frequently lower than even the straight-line depreciated value.

This is especially true for equipment that is only a year or two old, and in fact if a utility sells never-used surplus equipment it is common to receive 80 to 90 percent of its new value. In its second argument, Black and Veatch claims that value should never be less than the outstanding debt used to finance the subject equipment. This is clearly untrue, as anyone who has financed a car can attest. Value is determined in the marketplace, and has no direct correlation to the debt balance. In answer to the question, "Why would a seller willingly sell property for less than the outstanding indebtedness used to finance that asset?" we respond that such sales are not uncommon, for various reasons.

We also note that the observed condition of the system is more supportive of straight-line than present-worth depreciation.

- In the attached "Initial Power Flow Study Report" prepared by PG&E, PG&E claims that SSJID would have to purchase the transmission line from Jack Tone to Ripon Substation, or use it as a "special facility." We do not agree that the status of this line will change. PG&E states that it will own the transmission-side facilities at Jack Tone, so the line will remain directly connected to PG&E transmission facilities. Its status is not affected by the insertion of the Jack Tone Substation.

- In the attached "Initial Power Flow Study Report" prepared by PG&E, it is stated that the insertion of the Jack Tone Substation into the PG&E transmission system will create a reliability risk to PG&E and its customers. We disagree with this assessment. While there will be additional breakers and associated equipment attached to the transmission system, the diminution in reliability is negligible. Furthermore, the transmission line from Jack Tone to Ripon will be sectionalized from the Manteca – Melones Switching Station – Stanislaus circuit, thus reducing exposure on this circuit and improving reliability (again, in our estimation, by a negligible amount). Under PG&E's reasoning, every one of PG&E's distribution substations could be said to create a reliability risk to its transmission customers.

- Black & Veatch mentions, but does not calculate, generation/power supply stranded costs. The amount of load being removed from the PG&E system is so small (less than 1 percent) that we do not believe there will be identifiable stranded costs. If PG&E can document such costs, SSJID will be responsible for them, but we do not expect they will be material.

- Black & Veatch mentions, but does not calculate, transmission stranded costs. SSJID has no plans to use any other transmission provider to deliver power into its system, and indeed it is captive to the PG&E transmission system. Therefore there should be no transmission stranded costs.

- In its "Initial Power Flow Study Report" PG&E indicates that some transmission network upgrades will be required earlier than otherwise planned due to SSJID's takeover and the resulting transfer of load among substations. We understand that under California ISO and FERC rules, the transmission owner is responsible for network upgrades required to serve load of its transmission customers, and recovers those costs in transmission rates.

- The "plottage" values used to increase the land value are not justified by any actual data. We agree that this is a difficult number to pin down. In our experience the factor of two is on the high side for electric distribution right-of-way easements, but not so high as to be clearly unreasonable. However, the same factor is used for the substation sites. The cost to acquire these relatively large parcels is much lower on a percentage basis than for the many small easements. In our opinion, the plottage factor of two cannot be justified for the substation sites.

- After documenting that an arbitrary "going concern" value has sometimes been allowed in similar cases, with examples given at 9% and 13.9% of RCNLD, Black & Veatch arbitrarily sets going concern value at 25% of RCNLD and claims that this is a "conservative" value. In our view, this is unsubstantiated. Going concern value must be a real and measureable value. Some of the components of going concern value which are claimed in the Black & Veatch report are, in our opinion, unjustified or overstated, examples of which are outlined below:

    1. Costs incurred to attract potential customers. In much of the SSJID territory, PG&E has no competition and no such costs would have been incurred. Further, we have seen no evidence that PG&E has been aggressively pursuing customers in the area in which they compete with Modesto Irrigation District.

    2. Costs incurred in anticipation of attaching future customers. These costs would primarily be represented by facilities built with additional capacity to serve growing load. They are reflected in RCNLD. There might also be research and study costs, but most of these would be incurred whether or not additional future customers were anticipated.

    3. Maps, records, etc. These are legitimate costs, although they are not generally categorized as "going concern" costs. However, we note that the sample distribution plat maps (as well as substation drawings) we obtained from PG&E are scanned drawings rather than CADD/GIS drawings, and thus are technologically obsolete.

    4. New markets. These are speculative and unlikely to result in significant future income. For example, while broadband over power lines has been pursued for years, there is no evidence of technological breakthroughs which will give it a competitive advantage over other broadband technologies. There is at least as high a probability that competing technologies will enjoy a continuing advantage. And at this point in the development of cellular networks, the demand for new antenna sites in areas which already have coverage by multiple carriers is low. As to fiber optics, they are seldom installed on distribution facilities, since fiber to the customer has proven uneconomical, and PG&E will retain the transmission facilities which might be used for this purpose.

- Reliability restoration. The facilities identified in the report appear to be a reasonable solution, although we do not know whether they are optimized. The costs, similar to the RCN costs referenced earlier, appear to be high.

- Stranded costs. Black & Veatch indicates that “other” stranded costs will be provided at a later date.

## 7.1 ASSESSMENT OF THE SSJID BUSINESS PLAN

PA reviewed the business plan submitted by SSJID in relation to its application to provide electric service and its intended purchase of the PG&E distribution system. Specifically, SJ LAFCO has asked PA to analyze the feasibility of the plan and SSJID's contention that it can provide the same level of service to PG&E's existing customers at a rate 15% below PG&E rates. The rates presented in the business plan were PG&E rates as of March 2009. As PG&E has had a rate increase in March 2010, which PA relied upon in its income approach analysis, PA updated the revenue assumptions in the business plan to be 15% below the March 2010 rates, with rates assumed to escalate at 1.8%[9] annually. For the remainder of this chapter, references to assumed PG&E rates and business plan refer to the business plan using these updated rates. An analysis of the business plan using the PG&E rates assumed in SSJID's original business plan is presented in Appendix D.

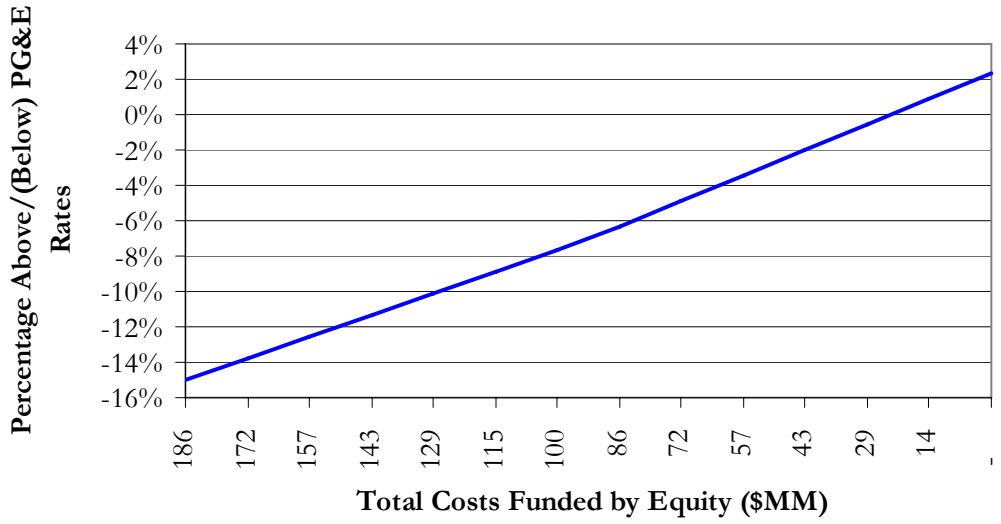
PA finds that SSJID's business plan is operationally feasible in that it has management personnel with experience in operating an electrical distribution system of the size that SSJID has suggested, substantial applicable experience in the operation of its water distribution and treatment facilities, and a generally realistic staffing and resource plan. However, PA finds that the underlying assumptions regarding purchase price would make SSJID's business plan, as it stands now, financially infeasible without raising assumed rates or infusing more equity than what is assumed. Furthermore, PA finds that SSJID's projected cost of power is understated in the long run and therefore could further impact the business plan by resulting in higher rates or additional equity. Both of these issues are discussed in more detail in sections 7.1.1 and 7.1.2 below.

PA adjusted SSJID's business plan for both PA's purchase price and capital requirements as well as PA's projected power prices. While SSJID's base case model assumes that the full purchase price can be financed through debt, a rise in the purchase price and associated costs and a rise in the cost of power causes debt service coverage ratios to fall below the 1.25 industry standard ratio test outlined in the SSJID model. Based on this, the model indicates SSJID would either need to provide more total cash upfront (equity) and/or raise rates above those assumed in the business plan[10]. This is demonstrated in Figure 7-1. At one end, SSJID would not need to change the discount of 15% to the assumed PG&E rates but would need to bring a total of $186 million of upfront cash, compared to the assumption that it would be fully funded through debt in its current business plan. At the other end, it would not need to bring any additional cash but would need to charge rates to approximately 2% above assumed PG&E rates.

[9] SSJID assumed 2% inflation in their original business plan but PA uses 1.8% to be consistent with its assumptions throughout the report.

[10] This case shows the impact of simultaneously adjusting the purchase price and cost of power assumptions, while sections 7.1.1 and 7.1.2 show the impacts of each adjustment individually. Adding the results of these individual cases will not equal the combined case, as combining them results in a compounding effect.

**Figure 7-1: Additional Equity and Discount in Rate Combinations using PA Forecasted Purchase Price and Cost of Power in SSJID business plan updated for March 2010 PG&E Rates**




It is also important to note that the debt requirements under the various scenarios will also change from the assumption that was in the original business plan. Table 7-1 presents the total cost for the purchase price plus other associated costs, assumed level of equity, assumed level of debt, and rate adjustment to PG&E rate assumptions for the each scenario at the two extremes of those presented in Figure 7-1, as compared to the original SSJID business plan.

**Table 7-1: Comparison of Adjusted Business Plan (Purchase Price and Cost of Power) to Original SSJID Business Plan**

| | Adjusted Business Plan (Additional Equity) | Adjusted Business Plan (Higher Rates) | Original SSJID Business Plan |
|---|---|---|---|
| Rate Adjustment to Assumed PG&E Rates (%) | -15 | 2 | -15 |
| Total Purchase Price and Other Associated Costs ($ million) | 281 | 281 | 130 |
| Debt ($MM) | 95 | 281 | 130 |
| Equity ($MM) | 186 | 0 | 10[1] |

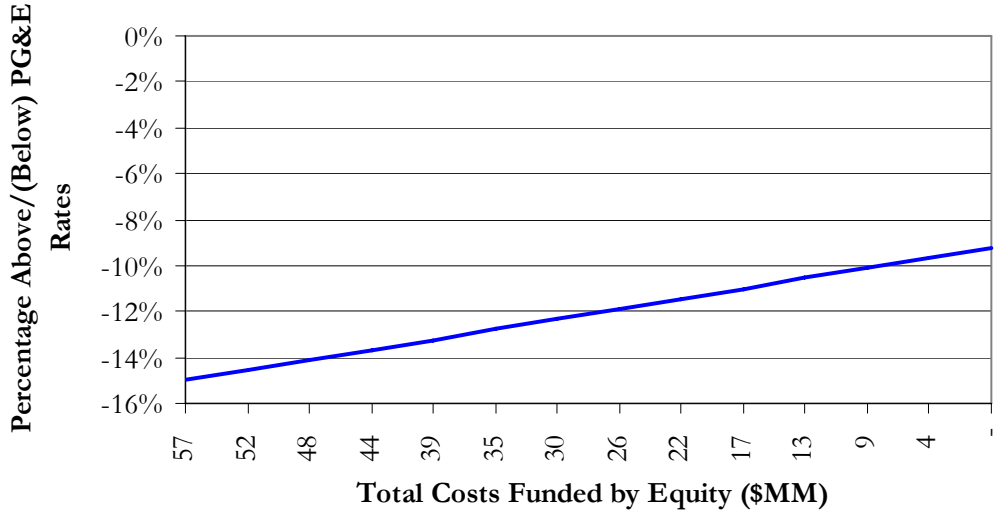
[1]Note that the $10MM equity infusion in the SSJID business plan is not required to fund total upfront costs

### 7.1.1 Purchase Price

PA has concluded that the purchase price of the Assets is higher than the purchase price used by SSJID in its original business plan. As a result, PA has tested SSJID's business plan by adjusting the purchase price plus incurred severance costs by SSJID to quantify the impact of such adjustments.

To ascertain the impact of the purchase price (holding all other factors constant), PA adjusted the purchase price and associated costs in SSJID's business plan model to equal those derived at the midpoint of PA's reconciled value of $218 million for the Assets and $19 million for capital upgrades. This is $150 million higher than SSJID's assumption of $65 million for the Assets and $22 million for capital upgrades. By adjusting these variables, PA inherently adjusted the forecasted cash flows to account for the rise in purchase price and associated costs. Debt service payments, including principal and interest payments, were adjusted upward to account for the rise in purchase price and associated costs. PA found that with a rise in purchase price and associated costs to levels consistent with PA's derived value, there would be a higher level of cash required upfront and/or SSJID would need to raise rates above the 15% discount to PG&E rates in order to maintain a 1.25 debt service coverage ratio. This is shown in Figure 7-2.

**Figure 7-2: Additional Equity and Discount in Rate Combinations using PA Forecasted Purchase Price and Associated Costs in SSJID business plan updated for March 2010 PG&E Rates**




Based on PA's value and associated cost, and holding all else equal, a maximum debt to capital ratio of approximately 80% would be feasible. While SSJID's model assumes $10 million of cash is infused into the project at the onset, a rise to approximately 20% of total costs being funded through equity would lead to a higher level of cash being required upfront. PA's analysis suggests an upfront cash requirement of approximately $57 million, which could impact the feasibility of SSJID's business plan. The associated debt with this scenario is presented in Table 7-2.

While adjusting the amount financed through equity and debt is one method in which SSJID could adjust its plan, provided a higher purchase price and associated costs, SSJID could also choose to raise rates to improve debt service coverage ratios. In this regard, PA found that under SSJID's base case assumptions, and provided the higher purchase price and associated costs, SSJID's plan to offer rates 15% below the assumed PG&E rates in the updated business plan was infeasible, as a 1.25 debt service coverage ratio could not be met. Instead, SSJID would need to adjust its discount in rates from 15% to approximately 9% below the assumed PG&E rates, in order to meet debt service coverage ratio requirements[11]. The associated debt with this scenario is presented in Table 7-2.

[11] This is the amount that rates would have to be to maintain a 1.25 debt service coverage for all years. Based on this average rate change, there are some years that the debt service coverage would be above 1.25 in which case the rates would not have to be as high.

**Table 7-2: Comparison of Adjusted Business Plan (Purchase Price) to Original SSJID Business Plan**

| | Adjusted Business Plan (Additional Equity) | Adjusted Business Plan (Higher Rates) | Original SSJID Business Plan |
|---|---|---|---|
| Rate Adjustment to Assumed PG&E Rates (%) | -15 | -9 | -15 |
| Total Purchase Price and Other Associated Costs ($ million) | 281 | 281 | 130 |
| Debt ($MM) | 224 | 281 | 130 |
| Equity ($MM) | 57 | 0 | 10[1] |

[1]Note that the $10MM equity infusion in the SSJID business plan is not required to fund total upfront costs

### 7.1.2 Cost of Power

A significant assumption in the SSJID business plan is how much it will cost to procure power for delivery to its customers. SSJID retained a quote of $82/MWh from Shell Energy North America (SENA) as an indicative offer that SENA would provide power to SSJID for a five year period from 2010-2014. It should be noted that this quote is from 2009 and therefore almost a year old, although through discussions with SENA they indicated that they did not think it would be a significant difference. This price is then escalated at inflation for the duration of the study period.

PA has extensive experience forecasting power prices for use in financings, contract negotiations and other transaction support. PA's price forecasting methodology is described in more detail in Appendix D. Table 7-3 provides a comparison of PA's power prices to those assumed in SSJID's business plan. PA presents four forecasts. The first two assume that power is procured from the wholesale market. The difference between Case 1 and Case 2 is that Case 2 assumes that SSJID procures 20% from renewable resources through 2020 and then 33% beginning in 2020, while Case 1 assumes that SSJID has no renewable procurement until 2020, when it has 33%. PA notes that SSJID, as a municipal entity, would not be required under the current standards in California to procure renewable power until 2020. However, SSJID has stated its intention to procure renewable power prior to the requirement. Case 2 is most similar to the case presented by SSJID in terms of assumptions regarding renewable procurement. Cases 3 and 4 assume that SSJID enters into a long term full requirements contract and pays full compensation for a Greenfield, or new unit to recover its going forward costs. The difference between Case 3 and 4 is that Case 3 assumes only a 33 % renewable procurement in 2020 while Case 4 assumes 20% through 2020 and 33% thereafter. Appendix E details PA's power price forecast assumptions and derivation for the forecasts presented herein. SSJID would have multiple choices in procuring power and could result in the range of cases 1 through 4, particularly in the short term. However, these cases largely converge beginning in 2014 with the only difference being the assumption of

renewable procurement. This is due to the fact that the market will need new capacity beginning in 2014 and therefore market prices will need to increase to reflect Greenfield, or new capacity.

**Table 7-3: Power Price Comparison**

| Year | SSJID forecast ($/MWh) | PA Case 1[1] ($/MWh) | PA Case 2[2] ($/MWh) | PA Case 3[3] ($/MWh) | PA Case 4[4] ($/MWh) |
|---|---|---|---|---|---|
| 2011 | 82 | 65 | 67 | 87 | 89 |
| 2012 | 84 | 68 | 70 | 90 | 91 |
| 2013 | 85 | 75 | 83 | 96 | 105 |
| 2014 | 87 | 100 | 107 | 100 | 107 |
| 2015 | 89 | 104 | 110 | 104 | 110 |
| 2016 | 91 | 108 | 114 | 108 | 114 |
| 2017 | 92 | 111 | 117 | 111 | 117 |
| 2018 | 94 | 115 | 121 | 115 | 121 |
| 2019 | 96 | 118 | 124 | 118 | 124 |
| 2020 | 98 | 129 | 129 | 129 | 129 |
| 2021 | 100 | 132 | 132 | 132 | 132 |
| 2022 | 102 | 136 | 136 | 136 | 136 |
| 2023 | 104 | 139 | 139 | 139 | 139 |
| 2024 | 106 | 141 | 141 | 141 | 141 |
| 2025 | 108 | 145 | 145 | 145 | 145 |
| 2026 | 110 | 147 | 147 | 147 | 147 |
| 2027 | 113 | 151 | 151 | 151 | 151 |

[1] Assumes power is procured in the spot market or at wholesale rates. Assumes SSJID meets 33% renewable requirement beginning in 2020. ‘

[2] Assumes power is procured in the spot market or at wholesale rates. Assumes SSJID meets 20% renewable requirement immediately and then 33% beginning in 2020.

[3] Assumes power is procured in a full requirements contract that represents full cost recovery to a new unit. Assumes SSJID meets 33% renewable requirement beginning in 2020.

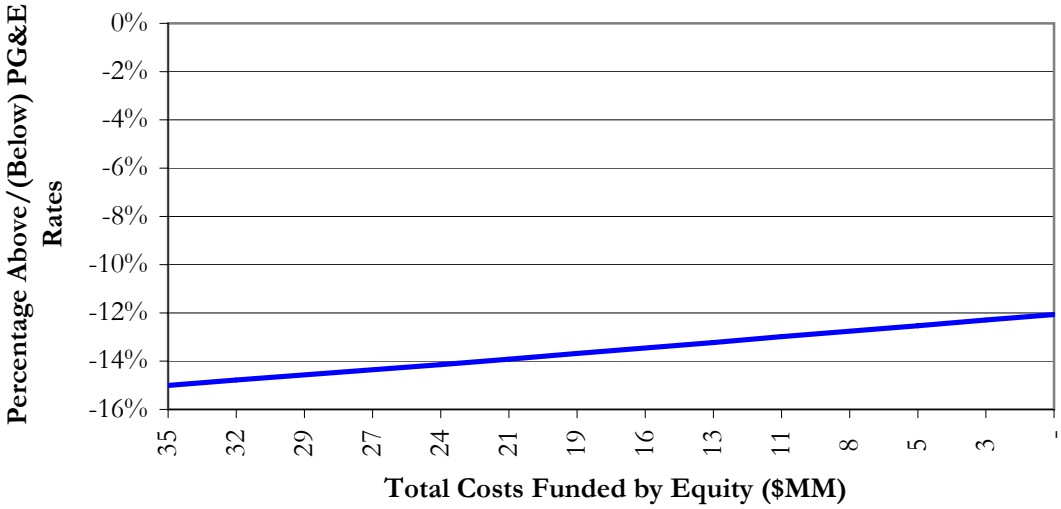
[4] Assumes power is procured in a full requirements contract that represents full cost recovery to a new unit. Assumes SSJID meets 20% renewable requirement immediately and then 33% beginning in 2020.

Based on these four cases, PA finds that SSJID’s assumption for the cost of power is reasonable for 2011-2014. However, PA’s price forecast diverges from that of SSJIDs

beginning in 2014 for three primary reasons; market recovery timing, natural gas prices and Greenhouse gas legislation/pricing. These three factors are expected to cause power prices to escalate at a rate higher than inflation. This is described more below.

Figure 7-3 presents additional equity and/or change to assumed discount in rates based on PA's cost of power assumptions for Case 2.

**Figure 7-3: Additional Equity and Discount in Rate Combinations using PA Forecasted Cost of Power (Case 2) in SSJID business plan updated for March 2010 PG&E Rates**

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PA finds that if SSJID was to adopt PA's forecast for cost of power, holding all other factors constant (including SSJID's assumed purchase price), SSJID would either need to increase its upfront cash requirement from $10 million to $35 million or increase its rates from a 15% discount to a 12% discount to the assumed PG&E rates in the updated business plan[12]. The associated debt for these two scenarios is presented in Table 7-4.

PA also reviewed Black and Veatch's power supply analysis and finds that in the short term (2011-2014) their estimate of cost to supply power is too high and appears reasonable for the long term.

[12] This is the amount that rates would have to be to maintain a 1.25 debt service coverage for all years. Based on this average rate change, there are some years that the debt service coverage would be above 1.25 in which case the rates would not have to be as high.

**Table 7-4: Comparison of Adjusted Business Plan (Cost of Power) to Original SSJID Business Plan**

| | Adjusted Business Plan (Additional Equity) | Adjusted Business Plan (Higher Rates) | Original SSJID Business Plan |
|---|---|---|---|
| Rate Adjustment to Assumed PG&E Rates (%) | -15 | -12 | -15 |
| Total Purchase Price and Other Associated Costs ($ million) | 130 | 130 | 130 |
| Debt ($MM) | 95 | 130 | 130 |
| Equity ($MM) | 25 | 0 | 10[1] |

[1]Note that the $10MM equity infusion in the SSJID business plan is not required to fund total upfront costs

### *A. MARKET RECOVERY*

In SSJID's "Response to Power Supply Issues", its states "SENA assumed that SSJID's supply will consist of renewable energy, resource adequacy and "brown energy" from the many plants in California that that sell their excess energy in the marketplace". PA does not find this assumption unreasonable and agrees that it is possible to procure power from the current market based on "brown energy" or existing plants. In fact, PA believes that if SSJID wanted to procure energy through a less firm, spot market, it could do so at rates lower than what has been assumed in the business plan for the near term. The reason this is a reasonable assumption is because California is currently considered "overbuilt" which is when the supply exceeds the demand, in excess of what is deemed necessary for reliability.

One metric that is often used to describe the balance between supply and demand in a given regional electricity market is the "reserve margin," defined as the extent to which supply of generating capacity exceeds peak electricity demand. A reserve margin of 15% indicates that supply exceeds expected peak demand by 15%. Holding other factors constant, lower reserve margins (less surplus generation) typically lead to higher power prices, since the less efficient (more expensive) capacity in the region is more often needed to satisfy electricity demand. Generally, regions have target reserve margins which are established to maintain reliability. If a region reaches that target, then new capacity must be added in order to maintain the reserve margin and reliability. This is referred to as equilibrium. As markets migrate toward equilibrium, when new build capacity is required to maintain a target reserve margin, overall market compensation is generally expected to increase to support the cost of these additions. PA projects that market equilibrium will occur in California in 2014 which is why there is a significant increase in prices in Cases 1 and 2. Cases 3 and 4 do not exhibit this increase, as the price of new generation is already assumed beginning in 2011. Because SSJID only projects power to increase at the rate of inflation, they neglect to recognize that the market will need to compensate for new generators once they are needed due to demand growth.

### *B. NATURAL GAS PRICES*

Natural gas prices are a significant driver to power prices in California. The price of electricity in any given hour is typically related to the operating costs of the marginal, or price-setting, generator. Assuming economic behavior by market participants, generating units are generally dispatched in order of their variable costs (units with lower costs are dispatched first and higher-cost units are dispatched as load grows), so the variable costs of the last (or marginal) unit needed to satisfy demand typically drives the regional power price. In California, power generators that burn natural gas are on the margin over 90% of the hours. Therefore, natural gas prices are a key driver to the power prices in California. Table 7-5 demonstrates the natural gas forecast that PA uses. Delivered natural gas prices for Northern California are based on PA's market-by-market view of regional and local transportation, demand seasonality and spot basis differentials to the Henry Hub. Henry Hub projections incorporate NYMEX futures as of December 31, 2009, for 2011. For 2012 and 2013, natural gas prices are trended toward a consensus forecast commencing in 2014, derived from projections published by the Energy Information Administration (EIA), Global Insight, and Strategic Energy & Economic Research, Inc. (SEER). As shown, gas prices are increasing on

average at 2.8% which is greater than the 2% escalation that SSJID assumes implicitly in their power price forecast.

**Table 7-5: Natural Gas Prices**

| Year | Henry Hub ($/MMBtu) | Northern California ($/MMBtu) | Growth Rate |
|---|---|---|---|
| 2011 | 6.34 | 6.76 | |
| 2012 | 6.48 | 6.91 | 2.2% |
| 2013 | 6.62 | 7.06 | 2.2% |
| 2014 | 6.76 | 7.21 | 2.2% |
| 2015 | 6.99 | 7.45 | 3.3% |
| 2016 | 7.31 | 7.78 | 4.4% |
| 2017 | 7.41 | 7.89 | 1.3% |
| 2018 | 7.57 | 8.06 | 2.2% |
| 2019 | 7.83 | 8.33 | 3.4% |
| 2020 | 8.04 | 8.56 | 2.7% |
| 2021 | 8.26 | 8.79 | 2.7% |
| 2022 | 8.53 | 9.06 | 3.1% |
| 2023 | 8.72 | 9.27 | 2.3% |
| 2024 | 8.88 | 9.44 | 1.8% |
| 2025 | 9.22 | 9.80 | 3.8% |
| 2026 | 9.49 | 10.07 | 2.8% |
| 2027 | 9.87 | 10.47 | 3.9% |
| Average | | | 2.8% |

### *C. GREENHOUSE GAS (MOST NOTABLY, CARBON DIOXIDE) REGULATIONS*

California is engaged in multiple initiatives to reduce greenhouse gas emissions, which has important implications for all power generating assets located in and delivering power to California and on power prices.

SB 1368 prohibits California utilities from entering into new long-term power purchase agreements unless the contracted baseload generation emits $CO_2$ at a level equal to or below that of a new natural gas combined cycle power generating asset. This standard applies to generation originating within the California market and, more significantly, power imports. The rule effectively prevents lower dispatch cost coal generation from being imported into the state on a long-term, contracted basis, but does not restrict purchase on a short-term basis.

In August 2006, California lawmakers approved the Global Warming Solutions Act (GWSA), calling for a return of California's emissions to 1990 levels by 2020. California is also part of the Western Climate Initiative (WCI), which is designed to regulate greenhouse gas emissions from six western states and four Canadian provinces under a cap-and-trade program beginning in 2012. Partners in the WCI jointly set regional emissions targets, currently set at reducing emissions levels to 15% below 2005 levels by 2020, although the target doesn't replace existing limits set by individual member states. Many program specific regulations are still being negotiated in the WCI working groups, including the important issue of potential preemption by a federal GHG program.

Additionally, several federal greenhouse gas emissions bills were proposed in previous sessions of Congress, each with varying constraints, and several more have been introduced in the current session. In particular, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009 (often referred to as Waxman-Markey) on June 26, 2009, which would start a federal cap-and-trade program in 2012.[13] As a result of the wide range of compliance costs associated with the various proposals, analyses by PA and several government agencies have projected $CO_2$ emission allowance prices ranging from $1 to more than $50 per short ton.

These programs would be expected to increase operating costs for most power generating assets and therefore increase power prices. Based on the momentum behind Greenhouse Gas legislation, PA feels that it would be imprudent to assume that there will be no such legislation in the future, which SSJID essentially does by only applying inflation to their 2011 power price.

PA's market prices assume implementation of WCI/GWSA in 2012 and a federal greenhouse gas emissions cap-and-trade program in 2013. PA assumes that programs such as the GWSA or WCI will be integrated with the federal program. PA's market prices assumes that the federal greenhouse gas emissions program ultimately selected will result in a compliance cost of $15/short ton of $CO_2$ in 2013, climbing to $30/short ton by 2023, based on analysis of

[13] Waxman-Markey calls for $CO_2$ emissions reduction targets (with a base year of 2005) of 17% by 2020, and 83% by 2050, with additional targets in the interim period.

proposed greenhouse gas emissions legislation and public, industry, and political reaction to the proposals.

## *8. CERTIFICATION*

I certify, to the best of my knowledge and belief, that:

- The statements of fact contained in this report are true and correct.
- The reported analyses, opinions, and conclusions are limited by the reported assumptions and limiting conditions, and are our unbiased professional analyses, opinions, and conclusions.
- We have no present or prospective interest in the Property that is the subject of this report, and we have no personal interest or bias with respect to the parties involved.
- Our compensation is not contingent upon the reporting of a predetermined value or direction in value that favors the cause of the client or involved parties, the amount of the value estimate, the attainment of a stipulated result, or the occurrence of a subsequent event.
- Our analyses, opinions, and conclusions were developed, and this report has been prepared, in conformity with the Uniform Standards of Professional Appraisal Practice of the Appraisal Foundation and the Principles of Appraisal Practice and Code of Ethics of the American Society of Appraisers.
- Members of my staff inspected the property that is the subject of this report.
- Individuals affiliated with PA Consulting Group, Inc., significantly contributing to this report are listed below:
  - Wayne Miller
  - Don Chambless
  - Kenyon Willhoit
  - Keturah Nelson
- This appraisal assignment was not based on a requested minimum valuation, a specific valuation, or the approval of a loan.
- The accredited senior appraiser certifying this appraisal report is in compliance with the mandatory recertification program administered by the American Society of Appraisers.

Sincerely,

Todd W. Filsinger
General Property Appraiser
Senior Accredited Appraiser
ASA Member I.D. 0109077

# Todd Filsinger

## Managing Partner

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### Primary expertise

- Due Diligence and Restructuring
- Valuations to support financing
- Market advisory
- Evaluation of generation, distribution and transmission properties

### Related expertise

- Expert testimony
- Property appraisal
- Asset management

### Qualifications

- University of Colorado, MBA, Business Administration, 1989
- Colorado State University, BS, Mechanical Engineering, 1985

Mr. Filsinger is a Member of PA's Management Group and the Global Head of the Energy Services Team. Mr. Filsinger's experience in the electric utility industry spans over 21 years. During his career, his breadth of experience has involved and is not limited to; restructuring, financing and evaluation of generation, distribution and transmission properties, and the development of critical strategies for the utility and merchant energy sectors. Mr. Filsinger had been actively involved in the deregulation of the energy markets across the United States. Mr. Filsinger is an internationally recognized expert in power markets and has led many organizations through complex and difficult business situations. Mr. Filsinger has most recently acted as the Interim Chief Operating Officer (COO) for Calpine Corporation with an EBITDA in excess of $1.5 billion per annum. As Interim COO, Mr. Filsinger was responsible for all aspects of Calpine's operations including Power, Commercial, Environmental Health and Safety, Engineering and Project Development.

Mr. Filsinger also worked with the presidential transition team, as well as forming and co-chairing the Coalition for the Green Bank. The Coalition was formed in order to advocate and support an entity funded by the government that would provide financing opportunities for clean energy technologies. Todd's work with the Coalition has involved managing and driving initiatives such as analysis and presentations used in discussions with members of Congress and other stakeholders, hosting and

Professional Affiliations and Societies

- Registered Professional Engineer in Colorado
- Senior Accredited Appraiser, American Society of Appraisers
- Member of the American Society of Mechanical Engineers
- Member of the National Society of Real Estate Appraisers
- Member of the American Society of Professional Cost Estimators

speaking at stakeholder conferences and meeting with Congressmen about the Green Bank and its goals. Through its work, the Coalition has facilitated the inclusion of the Clean Energy Deployment Administration (CEDA)/Green Bank in the Waxman Markey bill that passed in the House of Representatives, which encompasses many of the goals of the Coalition. While no longer part of the coalition, he continues to focus on state funded green banks and the creation of an international green bank.

## Primary expertise

Mr. Filsinger has participated in restructuring assignments addressing approximately 100,000 MW of generating capacity for the following companies:

- Calpine Corporation
- Mirant
- Cajun Electric Cooperative
- NRG Energy, Inc.
- Cogentrix
- Dynegy
- Allegheny Energy
- PG&E National Energy Group
- TECO Panda Generating
- AES Londonderry
- Petro Oil / Star Gas
- Exelon Boston Generating
- Reliant Resources
- AEP Texas, Coleto Creek
- Edison Mission Energy

**Services included the analysis of:**

- Generating assets involving estimates of gross margins, including existing fuel and off-take agreements
- Strategic restructuring alternatives
- Asset sales
- Development of power marketing and trading activities

- Upstream and downstream gas processing assets
- Operational costs and issues
- Capital expenditures
- Partially completed generation projects
- Corporate and project level debt
- Mr. Filsinger has also participated in the financings of over 50,000 MW of generating capacity.

## Record of Testimony

- Calpine Corporation, ET AL, December 2007
  United States Bankruptcy Court Southern District of New York
  regarding Chapter 11
  Case No. 05-60200
- Trans-Alaska Pipeline System, 2006
  Before the State Assessment Review Board, State of Alaska
  Appeal of Revenue Decision No. 06-56-17, OAH No. 06-SARB-TAX
  Oil & Gas Property Tax 2006 assessment year.
- Union Power Partners L.P., ET AL, April 2005
  United States Bankruptcy Court for the district of Arizona
  Case No. 05-01143
- Mirant Corporation, ET AL, 2004
  United States District Court for the Northern District of Texas Fort
  Worth Division regarding Chapter 11
  Case No. 03-46590-DML-11.
  Trial regarding hedging, trading and valuation issues.
- Enron Power Marketing, Inc., 2002
  Federal Energy Regulatory Commission
  Docket No.'s EL02-26-000, EL02-28-000, EL02-33-000, EL02-38-000.
- USGen New England, 2002
  Superior Court Windham County, VT
  Appeal of USGen New England, Inc. from 2001
  Property Valuation by the Town of Rockingham
  Docket No. 422-9-01 Wmc.

- AES, January 2002
  California State Assessment Board.
- Illinois Power Company, 2000-2001
  Third Judicial Circuit of Illinois, Madison County
  Illinois Power Company and Illinova Corporation vs.
  Wegman Electric Company, et al.
  Case No. 98-L-280.
- USGen New England, 2001
  Superior Court Windham County, VT
  Appeal of USGen New England from 1999 Property Valuation by the Towns of Whitingham and Rockingham
  Docket Nos. S362-9-99 and S372-9-99.
- Village of Lakewood, 1999
  New York Public Service Commission
  PSC Case 99 E 0681
  Property Valuation and Stranded Costs.
- Electric Rate Savers, L.L.C. v. New Jersey Sports and Exposition Authority, et al., 1999
  US District Court of New Jersey
  Civil Action No. 98-C4815 (MTB)
  Electric rates.
- Deseret Generation and Transmission Cooperative, 1998
  Utah Federal Court
  Valuation of Coal Facilities
- City of Las Cruces, NM, 1997-1998
  Federal Energy Regulatory Commission
  Utility Property Valuation
  FERN Case # SC96-002.
- City of Albuquerque, 1997
  New Mexico Public Utility Commission
  Proceeding Case # 2782
  Petition to Institute Retail Pilot Load Aggregation Program and Request for Related Approvals.

- Deseret Generation and Transmission Cooperative
  Colorado Board of Assessment, 1996
  Rio Blanco County # 28878 and Moffat County # 28877
  Utility Property Valuation
  Holmes, Roberts & Owens.
- Baltimore Gas & Electric, Potomac Electric Power Co., and Constellation Energy Corp., 1996
  Public Service Commission of District of Columbia
  Proceeding # 951
  Potential Impact on Rate Payers and Competitive Issues
  Washington Metropolitan Area Transit Authority.
- El Paso Electric Company, 1996
  United States District Court of New Mexico
  Proceeding # 95-485-LCS-8172
  Utility Condemnation/Severance Issues
  City of Las Cruces.
- Strawberry Utilities, 1994
  Fourth Judicial District Court in Utah
  Proceeding # 9104000443
  Utility Property Valuation
  City of Spanish Fork

## Additional experience

Mr. Filsinger has presented on the subjects of utility deregulation, market pricing, and utility appraisal. A list of recent courses, seminars and selected presentations held are noted below:

- Moody's Investor Services 2002
- Center for Business Intelligence 1998, 2000, 2001, 2002, 2003
- Platts Global Power Markets 2007, 2008, 2009, 2010
- Platts Financing US Power Markets 2008
- Infocast 2001, 2002, 2003, 2004, 2005
- Institute for Professional Taxation 2001
- Thompson Financial 2001

- Project Finance International 2001, 2002
- Société Générale Annual US Power Conference 2003, 2005
- Goldman Sachs Annual Power and Utility Conference 2006, 2007, 2008, 2009
- Lehman Brothers High Yield Bond and Syndicated Loan Conference 2003, 2005, 2006
- New York Power Authority Corporate Planning Conference 2003
- Large Public Power Council Conference 2003
- Citibank, N.A. Power Sector Research Conference 2003
- Credit Suisse First Boston Leveraged Finance Independent Power Producers and Utilities Conference 2003
- Exnet Conference on Utility Restructuring 2003, 2004
- FERC Western Energy Infrastructure Conference 2003
- Eurelectric Annual Conference 2003, 2004, 2005, 2006
- Shearman & Sterling and PA Power/Fuel Markets Seminars 2004, 2005, 2008
- Skadden, Arps, Slate, Meagher & Flom Energy & Project Finance Seminar 2004, 2005, 2006, 2008, 2009, 2010
- CoBank Energy Industry Update and Portfolio Management, and Executive Forum 2004
- McDermott, Will & Emery 7th Annual Energy Conference, 2004
- Royal Bank of Scotland North American Energy Offsite Conference, 2004
- Infocast Conference on Asset Valuation / Power Markets 2004
- AIRA (Association of Insolvency & Restructuring Advisors) Annual Conference 2005
- Energy & Mineral Law Foundation (EMLF) Winter Workshop on Energy Law 2004
- LCRA Energy Operations Committee and Board Meeting 2003
- Electric Power Conference 2004
- North American Power Credit Association (NAPCO) 2005.

- UBS Winter Outing and Power Markets Event 2009, 2010
- Coalition for the Green Bank - The Green Bank and America's Clean Energy Future – A Finance Perspective 2009
- Coalition for the Green Bank - Financing our Renewable Future 2009
- Clean Energy Council - Bridging the Financing Gap - Realizing America's Clean Energy Potential 2009

## Publications

- "Energy & Utilities Sector Roundtable" Financier Worldwide, Issue 58, October 2007
- "Merchant Asset Value Recovery: Turning the Corner on the Power Market Business Cycle" Managing Global Energy Risk, November 2005.
- "Forecasting Recovery of Merchant Asset Values: Boom/Bust Sends Shockwaves through Power Industry" Turnaround Management Association, November 2004.
- "Merchant Energy Road to Recovery: The Outlook from Inside of the Tunnel" The Journal of Structured and Project Finance, Fall 2003.
- "Power Generation and Industry Cycles: Lessons From Other Industries" PA Viewpoint article, 2002.
- "The Impacts of Electric Industry Deregulation and Restructuring on Electric Generating Facility Valuation and Ad Valorem Assessments." Presented at the Institute for Professionals in Taxation conference, 2001.

## Sales at Meter (MWh)

**Table B-1**

| | Residential | Commercial Class | Large Commercial Class | Industrial Class | Agriculture Class | Street Lighting | Total Sales at Meter | Growth Rate |
|---|---|---|---|---|---|---|---|---|
| 2011 | 273,500 | 52,068 | 161,413 | 29,695 | 17,044 | 4,131 | 537,851 | |
| 2012 | 277,863 | 52,899 | 163,988 | 30,169 | 17,316 | 4,196 | 546,430 | 1.6% |
| 2013 | 282,856 | 53,849 | 166,935 | 30,711 | 17,627 | 4,272 | 556,250 | 1.8% |
| 2014 | 286,651 | 54,572 | 169,174 | 31,123 | 17,863 | 4,329 | 563,713 | 1.3% |
| 2015 | 290,437 | 55,292 | 171,408 | 31,534 | 18,099 | 4,386 | 571,157 | 1.3% |
| 2016 | 294,360 | 56,039 | 173,724 | 31,960 | 18,344 | 4,446 | 578,872 | 1.4% |
| 2017 | 298,593 | 56,845 | 176,222 | 32,420 | 18,607 | 4,510 | 587,196 | 1.4% |
| 2018 | 302,663 | 57,620 | 178,624 | 32,862 | 18,861 | 4,571 | 595,201 | 1.4% |
| 2019 | 306,757 | 58,399 | 181,040 | 33,306 | 19,116 | 4,633 | 603,252 | 1.4% |
| 2020 | 311,060 | 59,218 | 183,580 | 33,774 | 19,384 | 4,698 | 611,714 | 1.4% |
| 2021 | 315,330 | 60,031 | 186,100 | 34,237 | 19,650 | 4,762 | 620,112 | 1.4% |
| 2022 | 319,659 | 60,856 | 188,655 | 34,707 | 19,920 | 4,828 | 628,625 | 1.4% |
| 2023 | 324,048 | 61,691 | 191,245 | 35,184 | 20,194 | 4,894 | 637,255 | 1.4% |
| 2024 | 328,497 | 62,538 | 193,870 | 35,667 | 20,471 | 4,961 | 646,004 | 1.4% |
| 2025 | 333,006 | 63,397 | 196,532 | 36,156 | 20,752 | 5,029 | 654,873 | 1.4% |
| 2026 | 337,578 | 64,267 | 199,230 | 36,653 | 21,037 | 5,098 | 663,863 | 1.4% |
| 2027 | 342,213 | 65,149 | 201,965 | 37,156 | 21,326 | 5,168 | 672,977 | 1.4% |
| 2028 | 346,911 | 66,044 | 204,738 | 37,666 | 21,618 | 5,239 | 682,216 | 1.4% |
| 2029 | 351,673 | 66,950 | 207,549 | 38,183 | 21,915 | 5,311 | 691,582 | 1.4% |
| 2030 | 356,501 | 67,869 | 210,398 | 38,707 | 22,216 | 5,384 | 701,076 | 1.4% |
| 2031 | 361,396 | 68,801 | 213,287 | 39,239 | 22,521 | 5,458 | 710,701 | 1.4% |
| 2032 | 366,357 | 69,746 | 216,215 | 39,777 | 22,830 | 5,533 | 720,458 | 1.4% |
| 2033 | 371,387 | 70,703 | 219,183 | 40,324 | 23,144 | 5,609 | 730,349 | 1.4% |
| 2034 | 376,485 | 71,674 | 222,192 | 40,877 | 23,461 | 5,686 | 740,376 | 1.4% |
| 2035 | 381,654 | 72,658 | 225,243 | 41,438 | 23,783 | 5,764 | 750,540 | 1.4% |
| 2036 | 386,894 | 73,655 | 228,335 | 42,007 | 24,110 | 5,843 | 760,844 | 1.4% |
| 2037 | 392,205 | 74,667 | 231,470 | 42,584 | 24,441 | 5,923 | 771,289 | 1.4% |
| 2038 | 397,589 | 75,692 | 234,647 | 43,169 | 24,777 | 6,005 | 781,878 | 1.4% |
| 2039 | 403,048 | 76,731 | 237,869 | 43,761 | 25,117 | 6,087 | 792,612 | 1.4% |
| 2040 | 408,581 | 77,784 | 241,134 | 44,362 | 25,461 | 6,171 | 803,494 | 1.4% |
| 2041 | 414,190 | 78,852 | 244,445 | 44,971 | 25,811 | 6,255 | 814,525 | 1.4% |
| 2042 | 419,877 | 79,935 | 247,801 | 45,588 | 26,165 | 6,341 | 825,707 | 1.4% |
| 2043 | 425,641 | 81,032 | 251,203 | 46,214 | 26,525 | 6,428 | 837,043 | 1.4% |
| 2044 | 431,484 | 82,144 | 254,651 | 46,849 | 26,889 | 6,517 | 848,534 | 1.4% |
| 2045 | 437,408 | 83,272 | 258,147 | 47,492 | 27,258 | 6,606 | 860,183 | 1.4% |

## Distribution Rates ($/kWh)

**Table B-2**

| | Residential (E1) | Commercial Class (A-1) | Large Commercial Class (A10-S) | Industrial Class (E-19S) | Agriculture Class (AG-4B) | Street Lighting |
|---|---|---|---|---|---|---|
| 2011 | 0.06814 | 0.06175 | 0.03518 | 0.02601 | 0.06643 | 0.06875 |
| 2012 | 0.06937 | 0.06286 | 0.03582 | 0.02648 | 0.06763 | 0.06998 |
| 2013 | 0.07062 | 0.06399 | 0.03646 | 0.02695 | 0.06885 | 0.07124 |
| 2014 | 0.07189 | 0.06515 | 0.03712 | 0.02744 | 0.07009 | 0.07253 |
| 2015 | 0.07319 | 0.06632 | 0.03778 | 0.02793 | 0.07135 | 0.07383 |
| 2016 | 0.07450 | 0.06751 | 0.03846 | 0.02844 | 0.07263 | 0.07516 |
| 2017 | 0.07584 | 0.06873 | 0.03916 | 0.02895 | 0.07394 | 0.07651 |
| 2018 | 0.07721 | 0.06997 | 0.03986 | 0.02947 | 0.07527 | 0.07789 |
| 2019 | 0.07860 | 0.07122 | 0.04058 | 0.03000 | 0.07663 | 0.07929 |
| 2020 | 0.08001 | 0.07251 | 0.04131 | 0.03054 | 0.07801 | 0.08072 |
| 2021 | 0.08145 | 0.07381 | 0.04205 | 0.03109 | 0.07941 | 0.08217 |
| 2022 | 0.08292 | 0.07514 | 0.04281 | 0.03165 | 0.08084 | 0.08365 |
| 2023 | 0.08441 | 0.07649 | 0.04358 | 0.03222 | 0.08229 | 0.08516 |
| 2024 | 0.08593 | 0.07787 | 0.04437 | 0.03280 | 0.08378 | 0.08669 |
| 2025 | 0.08748 | 0.07927 | 0.04516 | 0.03339 | 0.08528 | 0.08825 |
| 2026 | 0.08905 | 0.08070 | 0.04598 | 0.03399 | 0.08682 | 0.08984 |
| 2027 | 0.09066 | 0.08215 | 0.04680 | 0.03460 | 0.08838 | 0.09146 |
| 2028 | 0.09229 | 0.08363 | 0.04765 | 0.03522 | 0.08997 | 0.09310 |
| 2029 | 0.09395 | 0.08514 | 0.04850 | 0.03586 | 0.09159 | 0.09478 |
| 2030 | 0.09564 | 0.08667 | 0.04938 | 0.03650 | 0.09324 | 0.09648 |
| 2031 | 0.09736 | 0.08823 | 0.05027 | 0.03716 | 0.09492 | 0.09822 |
| 2032 | 0.09911 | 0.08982 | 0.05117 | 0.03783 | 0.09663 | 0.09999 |
| 2033 | 0.10090 | 0.09143 | 0.05209 | 0.03851 | 0.09837 | 0.10179 |
| 2034 | 0.10271 | 0.09308 | 0.05303 | 0.03920 | 0.10014 | 0.10362 |
| 2035 | 0.10456 | 0.09475 | 0.05398 | 0.03991 | 0.10194 | 0.10549 |
| 2036 | 0.10645 | 0.09646 | 0.05496 | 0.04063 | 0.10377 | 0.10738 |
| 2037 | 0.10836 | 0.09820 | 0.05595 | 0.04136 | 0.10564 | 0.10932 |
| 2038 | 0.11031 | 0.09996 | 0.05695 | 0.04210 | 0.10754 | 0.11128 |
| 2039 | 0.11230 | 0.10176 | 0.05798 | 0.04286 | 0.10948 | 0.11329 |
| 2040 | 0.11432 | 0.10359 | 0.05902 | 0.04363 | 0.11145 | 0.11533 |
| 2041 | 0.11638 | 0.10546 | 0.06008 | 0.04442 | 0.11346 | 0.11740 |
| 2042 | 0.11847 | 0.10736 | 0.06116 | 0.04522 | 0.11550 | 0.11952 |
| 2043 | 0.12060 | 0.10929 | 0.06227 | 0.04603 | 0.11758 | 0.12167 |
| 2044 | 0.12278 | 0.11126 | 0.06339 | 0.04686 | 0.11969 | 0.12386 |
| 2045 | 0.12499 | 0.11326 | 0.06453 | 0.04770 | 0.12185 | 0.12609 |

## Total Rates ($/kWh)

**Table B-3**

| | Residential (E1) | Commercial Class (A-1) | Large Commercial Class (A10-S) | Industrial Class (E-19S) | Agriculture Class (AG-4B) | Street Lighting |
|---|---|---|---|---|---|---|
| 2011 | 0.19235 | 0.18938 | 0.16812 | 0.14639 | 0.18369 | 0.16786 |
| 2012 | 0.19581 | 0.19279 | 0.17115 | 0.14902 | 0.18699 | 0.17088 |
| 2013 | 0.19934 | 0.19626 | 0.17423 | 0.15171 | 0.19036 | 0.17396 |
| 2014 | 0.20293 | 0.19979 | 0.17737 | 0.15444 | 0.19379 | 0.17709 |
| 2015 | 0.20658 | 0.20339 | 0.18056 | 0.15722 | 0.19727 | 0.18027 |
| 2016 | 0.21030 | 0.20705 | 0.18381 | 0.16005 | 0.20083 | 0.18352 |
| 2017 | 0.21408 | 0.21077 | 0.18712 | 0.16293 | 0.20444 | 0.18682 |
| 2018 | 0.21794 | 0.21457 | 0.19049 | 0.16586 | 0.20812 | 0.19019 |
| 2019 | 0.22186 | 0.21843 | 0.19391 | 0.16885 | 0.21187 | 0.19361 |
| 2020 | 0.22585 | 0.22236 | 0.19740 | 0.17188 | 0.21568 | 0.19709 |
| 2021 | 0.22992 | 0.22636 | 0.20096 | 0.17498 | 0.21956 | 0.20064 |
| 2022 | 0.23406 | 0.23044 | 0.20457 | 0.17813 | 0.22351 | 0.20425 |
| 2023 | 0.23827 | 0.23459 | 0.20826 | 0.18133 | 0.22754 | 0.20793 |
| 2024 | 0.24256 | 0.23881 | 0.21201 | 0.18460 | 0.23163 | 0.21167 |
| 2025 | 0.24692 | 0.24311 | 0.21582 | 0.18792 | 0.23580 | 0.21548 |
| 2026 | 0.25137 | 0.24748 | 0.21971 | 0.19130 | 0.24005 | 0.21936 |
| 2027 | 0.25589 | 0.25194 | 0.22366 | 0.19475 | 0.24437 | 0.22331 |
| 2028 | 0.26050 | 0.25647 | 0.22769 | 0.19825 | 0.24877 | 0.22733 |
| 2029 | 0.26519 | 0.26109 | 0.23179 | 0.20182 | 0.25324 | 0.23142 |
| 2030 | 0.26996 | 0.26579 | 0.23596 | 0.20545 | 0.25780 | 0.23559 |
| 2031 | 0.27482 | 0.27057 | 0.24020 | 0.20915 | 0.26244 | 0.23983 |
| 2032 | 0.27977 | 0.27544 | 0.24453 | 0.21292 | 0.26717 | 0.24414 |
| 2033 | 0.28480 | 0.28040 | 0.24893 | 0.21675 | 0.27198 | 0.24854 |
| 2034 | 0.28993 | 0.28545 | 0.25341 | 0.22065 | 0.27687 | 0.25301 |
| 2035 | 0.29515 | 0.29059 | 0.25797 | 0.22462 | 0.28186 | 0.25757 |
| 2036 | 0.30046 | 0.29582 | 0.26262 | 0.22867 | 0.28693 | 0.26220 |
| 2037 | 0.30587 | 0.30114 | 0.26734 | 0.23278 | 0.29209 | 0.26692 |
| 2038 | 0.31138 | 0.30656 | 0.27216 | 0.23697 | 0.29735 | 0.27173 |
| 2039 | 0.31698 | 0.31208 | 0.27705 | 0.24124 | 0.30270 | 0.27662 |
| 2040 | 0.32269 | 0.31770 | 0.28204 | 0.24558 | 0.30815 | 0.28160 |
| 2041 | 0.32849 | 0.32342 | 0.28712 | 0.25000 | 0.31370 | 0.28667 |
| 2042 | 0.33441 | 0.32924 | 0.29229 | 0.25450 | 0.31935 | 0.29183 |
| 2043 | 0.34043 | 0.33517 | 0.29755 | 0.25908 | 0.32509 | 0.29708 |
| 2044 | 0.34655 | 0.34120 | 0.30290 | 0.26374 | 0.33095 | 0.30243 |
| 2045 | 0.35279 | 0.34734 | 0.30835 | 0.26849 | 0.33690 | 0.30787 |

## Income Approach – Municipal Pro Forma

| $000s | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Revenues** | | | | | | | | | | | | |
| Distribution | 29,720 | 30,738 | 31,854 | 32,862 | 33,895 | 34,972 | 36,113 | 37,264 | 38,448 | 39,689 | 40,958 | 42,268 |
| **Total Revenues** | 29,720 | 30,738 | 31,854 | 32,862 | 33,895 | 34,972 | 36,113 | 37,264 | 38,448 | 39,689 | 40,958 | 42,268 |
| **Expenses** | | | | | | | | | | | | |
| O&M/A&G Costs | 9,155 | 9,320 | 9,488 | 9,659 | 9,833 | 10,010 | 10,190 | 10,373 | 10,560 | 10,750 | 10,944 | 11,141 |
| Public Benefit Costs | 1,956 | 2,022 | 2,096 | 2,162 | 2,230 | 2,301 | 2,376 | 2,452 | 2,530 | 2,611 | 2,695 | 2,781 |
| Payments in Lieu of Taxes | 1,956 | 2,022 | 2,096 | 2,162 | 2,230 | 2,301 | 2,376 | 2,452 | 2,530 | 2,611 | 2,695 | 2,781 |
| Nonbypassable Payments to PG&E | 3,914 | 3,989 | 2,896 | 2,951 | 3,007 | 3,065 | 3,123 | 3,183 | 3,243 | 3,305 | 3,368 | 3,433 |
| **Total Expenses** | 16,980 | 17,354 | 16,576 | 16,934 | 17,300 | 17,676 | 18,065 | 18,460 | 18,863 | 19,278 | 19,702 | 20,135 |
| **EBITDA** | **12,740** | **13,384** | **15,278** | **15,928** | **16,595** | **17,295** | **18,048** | **18,805** | **19,585** | **20,411** | **21,256** | **22,132** |
| Capital Expenditures | 7,500 | 7,635 | 7,772 | 7,912 | 8,055 | 8,200 | 8,347 | 8,498 | 8,651 | 8,806 | 8,965 | 9,126 |
| **Unlevered Pre-Tax Cash Flow** | **5,240** | **5,749** | **7,505** | **8,015** | **8,540** | **9,095** | **9,700** | **10,307** | **10,935** | **11,605** | **12,292** | **13,006** |
| Income Tax Expense/(Benefit) | - | - | - | - | - | - | - | - | - | - | - | - |
| **Unlevered After-Tax Cash Flow** | **5,240** | **5,749** | **7,505** | **8,015** | **8,540** | **9,095** | **9,700** | **10,307** | **10,935** | **11,605** | **12,292** | **13,006** |

| $000s | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Revenues** | | | | | | | | | | | | |
| Distribution | 43,619 | 45,014 | 46,454 | 47,939 | 49,472 | 51,054 | 52,686 | 54,371 | 56,109 | 57,904 | 59,755 | 61,666 |
| **Total Revenues** | 43,619 | 45,014 | 46,454 | 47,939 | 49,472 | 51,054 | 52,686 | 54,371 | 56,109 | 57,904 | 59,755 | 61,666 |
| **Expenses** | | | | | | | | | | | | |
| O&M/A&G Costs | 11,341 | 11,545 | 11,753 | 11,965 | 12,180 | 12,399 | 12,622 | 12,850 | 13,081 | 13,316 | 13,556 | 13,800 |
| Public Benefit Costs | 2,870 | 2,962 | 3,057 | 3,154 | 3,255 | 3,359 | 3,467 | 3,577 | 3,692 | 3,810 | 3,932 | 4,057 |
| Payments in Lieu of Taxes | 2,870 | 2,962 | 3,057 | 3,154 | 3,255 | 3,359 | 3,467 | 3,577 | 3,692 | 3,810 | 3,932 | 4,057 |
| Nonbypassable Payments to PG&E | 192 | 194 | 196 | 200 | 204 | 208 | 212 | 216 | 220 | 224 | 229 | 233 |
| **Total Expenses** | 17,273 | 17,663 | 18,062 | 18,473 | 18,894 | 19,325 | 19,767 | 20,220 | 20,685 | 21,161 | 21,648 | 22,148 |
| **EBITDA** | **26,346** | **27,351** | **28,391** | **29,466** | **30,578** | **31,728** | **32,919** | **34,150** | **35,425** | **36,743** | **38,107** | **39,517** |
| Capital Expenditures | 9,290 | 9,458 | 9,628 | 9,801 | 9,978 | 10,157 | 10,340 | 10,526 | 10,716 | 10,908 | 11,105 | 11,305 |
| **Unlevered Pre-Tax Cash Flow** | **17,056** | **17,894** | **18,764** | **19,665** | **20,600** | **21,571** | **22,579** | **23,624** | **24,709** | **25,834** | **27,002** | **28,213** |
| Income Tax Expense/(Benefit) | - | - | - | - | - | - | - | - | - | - | - | - |
| **Unlevered After-Tax Cash Flow** | **17,056** | **17,894** | **18,764** | **19,665** | **20,600** | **21,571** | **22,579** | **23,624** | **24,709** | **25,834** | **27,002** | **28,213** |

| $000s | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Revenues** | | | | | | | | | | | |
| Distribution | 63,638 | 65,672 | 67,772 | 69,939 | 72,176 | 74,484 | 76,865 | 79,323 | 81,860 | 84,477 | 87,178 |
| **Total Revenues** | 63,638 | 65,672 | 67,772 | 69,939 | 72,176 | 74,484 | 76,865 | 79,323 | 81,860 | 84,477 | 87,178 |
| **Expenses** | | | | | | | | | | | |
| O&M/A&G Costs | 14,048 | 14,301 | 14,559 | 14,821 | 15,088 | 15,359 | 15,636 | 15,917 | 16,204 | 16,495 | 16,792 |
| Public Benefit Costs | 4,187 | 4,321 | 4,459 | 4,602 | 4,749 | 4,901 | 5,058 | 5,219 | 5,386 | 5,558 | 5,736 |
| Payments in Lieu of Taxes | 4,187 | 4,321 | 4,459 | 4,602 | 4,749 | 4,901 | 5,058 | 5,219 | 5,386 | 5,558 | 5,736 |
| Nonbypassable Payments to PG&E | 238 | 243 | 247 | 252 | 257 | 262 | 267 | 272 | 277 | 282 | 287 |
| **Total Expenses** | 22,661 | 23,186 | 23,725 | 24,277 | 24,843 | 25,423 | 26,018 | 26,627 | 27,252 | 27,894 | 28,551 |
| **EBITDA** | **40,977** | **42,486** | **44,048** | **45,663** | **47,333** | **49,061** | **50,848** | **52,696** | **54,607** | **56,584** | **58,627** |
| Capital Expenditures | 11,508 | 11,715 | 11,926 | 12,141 | 12,359 | 12,582 | 12,808 | 13,039 | 13,274 | 13,513 | 13,756 |
| **Unlevered Pre-Tax Cash Flow** | **29,469** | **30,771** | **32,122** | **33,522** | **34,974** | **36,479** | **38,039** | **39,657** | **41,333** | **43,071** | **44,872** |
| Income Tax Expense/(Benefit) | - | - | - | - | - | - | - | - | - | - | - |
| **Unlevered After-Tax Cash Flow** | **29,469** | **30,771** | **32,122** | **33,522** | **34,974** | **36,479** | **38,039** | **39,657** | **41,333** | **43,071** | **44,872** |

## Income Approach – Regulated Utility Pro Forma

| $000s | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Revenues** | | | | | | | | | | | | |
| Distribution | 29,720 | 30,738 | 31,854 | 32,862 | 33,895 | 34,972 | 36,113 | 37,264 | 38,448 | 39,689 | 40,958 | 42,268 |
| **Total Revenues** | 29,720 | 30,738 | 31,854 | 32,862 | 33,895 | 34,972 | 36,113 | 37,264 | 38,448 | 39,689 | 40,958 | 42,268 |
| **Expenses** | | | | | | | | | | | | |
| O&M/A&G Costs | 9,155 | 9,320 | 9,488 | 9,659 | 9,833 | 10,010 | 10,190 | 10,373 | 10,560 | 10,750 | 10,944 | 11,141 |
| Public Benefit Costs | 1,956 | 2,022 | 2,096 | 2,162 | 2,230 | 2,301 | 2,376 | 2,452 | 2,530 | 2,611 | 2,695 | 2,781 |
| Franchise Fees and Property Taxes | 1,956 | 2,022 | 2,096 | 2,162 | 2,230 | 2,301 | 2,376 | 2,452 | 2,530 | 2,611 | 2,695 | 2,781 |
| Nonbypassable Payments to PG&E | 3,914 | 3,989 | 2,896 | 2,951 | 3,007 | 3,065 | 3,123 | 3,183 | 3,243 | 3,305 | 3,368 | 3,433 |
| **Total Expenses** | 16,980 | 17,354 | 16,576 | 16,934 | 17,300 | 17,676 | 18,065 | 18,460 | 18,863 | 19,278 | 19,702 | 20,135 |
| **EBITDA** | **12,740** | **13,384** | **15,278** | **15,928** | **16,595** | **17,295** | **18,048** | **18,805** | **19,585** | **20,411** | **21,256** | **22,132** |
| Capital Expenditures | 7,500 | 7,635 | 7,772 | 7,912 | 8,055 | 8,200 | 8,347 | 8,498 | 8,651 | 8,806 | 8,965 | 9,126 |
| **Unlevered Pre-Tax Cash Flow** | **5,240** | **5,749** | **7,505** | **8,015** | **8,540** | **9,095** | **9,700** | **10,307** | **10,935** | **11,605** | **12,292** | **13,006** |
| Income Tax Expense/(Benefit) | 3,478 | 2,039 | 2,831 | 3,111 | 3,392 | 3,682 | 3,988 | 4,291 | 4,473 | 4,644 | 4,820 | 5,006 |
| **Unlevered After-Tax Cash Flow** | **1,762** | **3,710** | **4,674** | **4,905** | **5,148** | **5,414** | **5,712** | **6,016** | **6,462** | **6,960** | **7,471** | **8,000** |

| $000s | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Revenues** | | | | | | | | | | | | |
| Distribution | 43,619 | 45,014 | 46,454 | 47,939 | 49,472 | 51,054 | 52,686 | 54,371 | 56,109 | 57,904 | 59,755 | 61,666 |
| **Total Revenues** | 43,619 | 45,014 | 46,454 | 47,939 | 49,472 | 51,054 | 52,686 | 54,371 | 56,109 | 57,904 | 59,755 | 61,666 |
| **Expenses** | | | | | | | | | | | | |
| O&M/A&G Costs | 11,341 | 11,545 | 11,753 | 11,965 | 12,180 | 12,399 | 12,622 | 12,850 | 13,081 | 13,316 | 13,556 | 13,800 |
| Public Benefit Costs | 2,870 | 2,962 | 3,057 | 3,154 | 3,255 | 3,359 | 3,467 | 3,577 | 3,692 | 3,810 | 3,932 | 4,057 |
| Franchise Fees and Property Taxes | 2,870 | 2,962 | 3,057 | 3,154 | 3,255 | 3,359 | 3,467 | 3,577 | 3,692 | 3,810 | 3,932 | 4,057 |
| Nonbypassable Payments to PG&E | 192 | 194 | 196 | 200 | 204 | 208 | 212 | 216 | 220 | 224 | 229 | 233 |
| **Total Expenses** | 17,273 | 17,663 | 18,062 | 18,473 | 18,894 | 19,325 | 19,767 | 20,220 | 20,685 | 21,161 | 21,648 | 22,148 |
| **EBITDA** | **26,346** | **27,351** | **28,391** | **29,466** | **30,578** | **31,728** | **32,919** | **34,150** | **35,425** | **36,743** | **38,107** | **39,517** |
| Capital Expenditures | 9,290 | 9,458 | 9,628 | 9,801 | 9,978 | 10,157 | 10,340 | 10,526 | 10,716 | 10,908 | 11,105 | 11,305 |
| **Unlevered Pre-Tax Cash Flow** | **17,056** | **17,894** | **18,764** | **19,665** | **20,600** | **21,571** | **22,579** | **23,624** | **24,709** | **25,834** | **27,002** | **28,213** |
| Income Tax Expense/(Benefit) | 6,549 | 6,781 | 7,024 | 7,278 | 7,544 | 7,822 | 8,113 | 8,418 | 9,754 | 11,176 | 11,663 | 12,168 |
| **Unlevered After-Tax Cash Flow** | **10,507** | **11,113** | **11,740** | **12,387** | **13,057** | **13,749** | **14,466** | **15,207** | **14,955** | **14,659** | **15,339** | **16,044** |

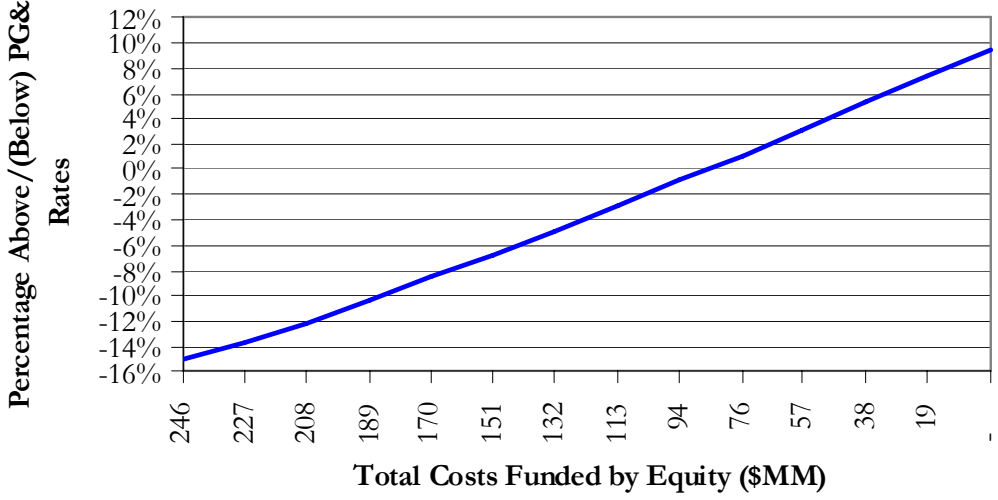
| $000s | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Revenues** | | | | | | | | | | | |
| Distribution | 63,638 | 65,672 | 67,772 | 69,939 | 72,176 | 74,484 | 76,865 | 79,323 | 81,860 | 84,477 | 87,178 |
| **Total Revenues** | 63,638 | 65,672 | 67,772 | 69,939 | 72,176 | 74,484 | 76,865 | 79,323 | 81,860 | 84,477 | 87,178 |
| **Expenses** | | | | | | | | | | | |
| O&M/A&G Costs | 14,048 | 14,301 | 14,559 | 14,821 | 15,088 | 15,359 | 15,636 | 15,917 | 16,204 | 16,495 | 16,792 |
| Public Benefit Costs | 4,187 | 4,321 | 4,459 | 4,602 | 4,749 | 4,901 | 5,058 | 5,219 | 5,386 | 5,558 | 5,736 |
| Franchise Fees and Property Taxes | 4,187 | 4,321 | 4,459 | 4,602 | 4,749 | 4,901 | 5,058 | 5,219 | 5,386 | 5,558 | 5,736 |
| Nonbypassable Payments to PG&E | 238 | 243 | 247 | 252 | 257 | 262 | 267 | 272 | 277 | 282 | 287 |
| **Total Expenses** | 22,661 | 23,186 | 23,725 | 24,277 | 24,843 | 25,423 | 26,018 | 26,627 | 27,252 | 27,894 | 28,551 |
| **EBITDA** | **40,977** | **42,486** | **44,048** | **45,663** | **47,333** | **49,061** | **50,848** | **52,696** | **54,607** | **56,584** | **58,627** |
| Capital Expenditures | 11,508 | 11,715 | 11,926 | 12,141 | 12,359 | 12,582 | 12,808 | 13,039 | 13,274 | 13,513 | 13,756 |
| **Unlevered Pre-Tax Cash Flow** | **29,469** | **30,771** | **32,122** | **33,522** | **34,974** | **36,479** | **38,039** | **39,657** | **41,333** | **43,071** | **44,872** |
| Income Tax Expense/(Benefit) | 12,692 | 13,235 | 13,798 | 14,381 | 14,986 | 15,612 | 16,262 | 16,934 | 17,632 | 18,354 | 19,102 |
| **Unlevered After-Tax Cash Flow** | **16,777** | **17,536** | **18,324** | **19,141** | **19,988** | **20,866** | **21,778** | **22,722** | **23,702** | **24,717** | **25,770** |

## *APPENDIX D: BUSINESS PLAN TESTS USING SSJID ORIGINAL BUSINESS PLAN*

PA performed the same business plan tests presented in Chapter 7 on the business plan and financial model submitted by SSJID to SJ LAFCo. This model assumed the PG&E rates as of March 2009 and escalated them at 2% each year thereafter.

Figure D-1 presents the results of using both PA's projected purchase price and cost of power in this model. As illustrated, SSJID would need to either provide $246 million in total cash upfront in order to maintain the 15% discount to PG&E's assumed rates, raise rates to be 9% above the assumed PG&E rates and provide no additional cash upfront, or do some combination of upfront cash and a change in assumed discount to rates illustrated in Figure D-1.

**Figure D-1: Additional Equity and Discount in Rate Combinations using PA Forecasted Purchase Price and Cost of Power in SSJID Original Business Plan**




It is also important to note that the debt requirements under the various scenarios will also change from the assumption that was in the original business plan. Table D-1 presents the total upfront cost, assumed level of equity, assumed level of debt, and rate adjustment to PG&E rates assumptions for the two extremes presented in Figure D-1, as compared to the original SSJID business plan.

**Table D-1: Comparison of Adjusted Business Plan (Purchase Price and Cost of Power) to Original SSJID Business Plan**

| | Adjusted Business Plan (Additional Equity) | Adjusted Business Plan (Higher Rates) | Original SSJID Business Plan |
|---|---|---|---|
| Rate Adjustment to Assumed PG&E Rates (%) | -15 | 9 | -15 |
| Total Purchase Price and Other Associated Costs ($ million) | 281 | 281 | 130 |
| Debt ($MM) | 35 | 281 | 130 |
| Equity ($MM) | 246 | 0 | 10[1] |

[1]Note that the $10MM equity infusion in the SSJID business plan is not required to fund total upfront costs

### D.1.1 Purchase Price

PA tested the impact on SSJID's original business plan of changing the purchase price using PA's reconciled value of $218 million for the assets and $19 million for capital upgrades and holding all else equal as described in Chapter 7. Figure D-2 presents the results of this test. PA's analysis suggests an upfront cash requirement of approximately $117 million in order to maintain the 15% discount to assumed PG&E rates, a change to the discount in rates from 15% to 2% and no additional cash needs from SSJID, or some combination of upfront cash and change in rates illustrated in Figure D-2.

**Figure D-2: Additional Equity and Discount in Rate Combinations using PA Forecasted Purchase Price in SSJID Original Business Plan**

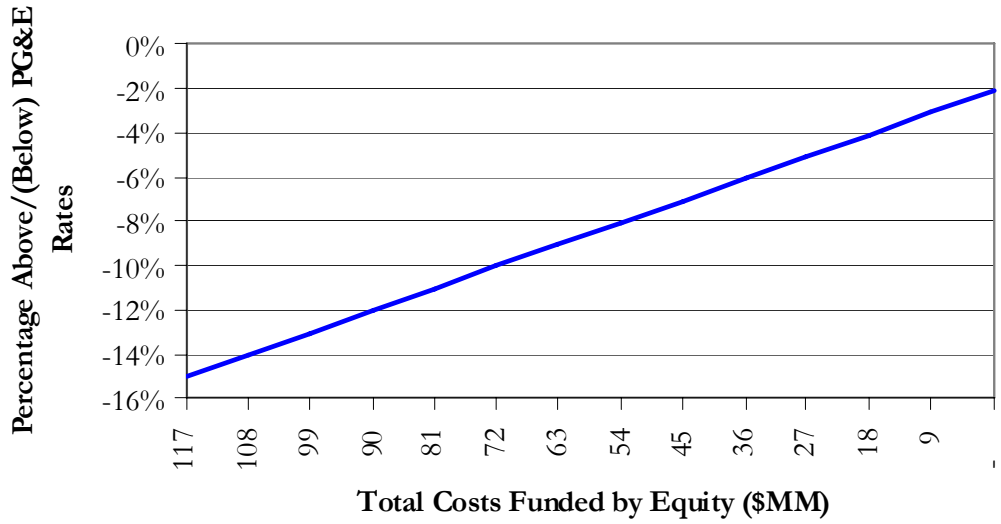



**Table D-2: Comparison of Adjusted Business Plan (Purchase Price) to Original SSJID Business Plan**

| | Adjusted Business Plan (Additional Equity) | Adjusted Business Plan (Higher Rates) | Original SSJID Business Plan |
|---|---|---|---|
| Rate Adjustment to Assumed PG&E Rates (%) | -15 | -2 | -15 |
| Total Purchase Price and Other Associated Costs ($ million) | 281 | 281 | 130 |
| Debt ($MM) | 164 | 281 | 130 |
| Equity ($MM) | 117 | 0 | 10[1] |

[1]Note that the $10MM equity infusion in the SSJID business plan is not required to fund total upfront costs

### D.1.2 Cost of Power

PA tested the impact on SSJID's original business plan of changing the cost of power by using PA's Case 2 power prices presented in Chapter 7. Figure D-3 presents the results of this test. PA's analysis suggests an upfront cash requirement of approximately $95 million in order to maintain the 15% discount to assumed PG&E rates, a change to the discount in rates from 15% to 7% and no additional cash needs from SSJID, or some combination of upfront cash and change in rates illustrated in Figure D-3. Table D-3 presents the total upfront cost, assumed level of equity, assumed level of debt, and rate adjustment to PG&E rates assumptions for the two extremes presented in Figure D-3, as compared to the original SSJID business plan.

**Figure D-3: Additional Equity and Discount in Rate Combinations using PA Forecasted Cost of Power (Case 2) in SSJID Original Business Plan**

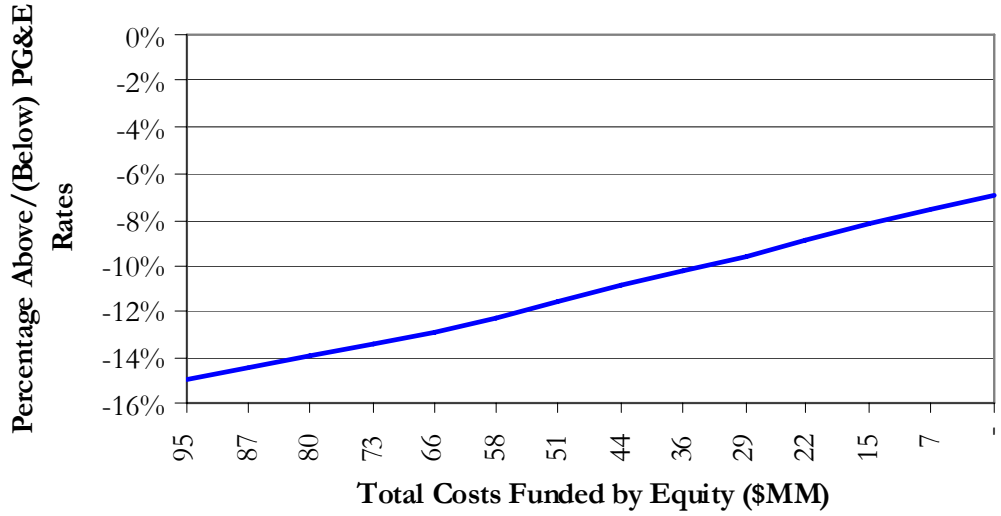


**Table D-3: Comparison of Adjusted Business Plan (Cost of Power) to Original SSJID Business Plan**

| | Adjusted Business Plan (Additional Equity) | Adjusted Business Plan (Higher Rates) | Original SSJID Business Plan |
|---|---|---|---|
| Rate Adjustment to Assumed PG&E Rates (%) | -15 | -7 | -15 |
| Total Purchase Price and Other Associated Costs ($ million) | 130 | 130 | 130 |
| Debt ($MM) | 35 | 130 | 130 |
| Equity ($MM) | 95 | 0 | 10[1] |

[1]Note that the $10MM equity infusion in the SSJID business plan is not required to fund total upfront costs

## *APPENDIX E: PA'S MODELING METHODOLOGY*

### E.1 INTRODUCTION

PA uses a bottom up approach to forecasting market electricity prices and power generating asset cash flows. This process is formed around a fundamental analysis. As part of the fundamental analysis, PA develops assumptions using an approach that continuously combines research, data and industry knowledge. PA translates the insight gained from published industry data and its proprietary inputs into modeling inputs, thus power generating asset results.

Two principles are fundamental to PA's approach:

- ***Supply and demand equilibrium:*** Power markets migrate toward a balance between capacity and load.
- ***Compensation for generation:*** Generators are compensated for more than the marginal cost of generation.

#### E.1.1 Supply and demand equilibrium

A fundamental tenet of PA's approach is that market participants continuously adjust toward economic equilibrium conditions by making decisions to add or retire generating capacity. Participants respond to the opportunity to capture excess margins through entry and the inverse opportunity to exit when expected returns do not justify ongoing costs. As a consequence, neither excessively high nor excessively low returns should persist over the long term because participants will change the level of supply until a balance with demand is reached. While PA believes that markets gravitate toward equilibrium conditions, participants often react to both below- and above-market returns causing pendulum-like price variations over time.[14]

#### E.1.2 Compensation for generation

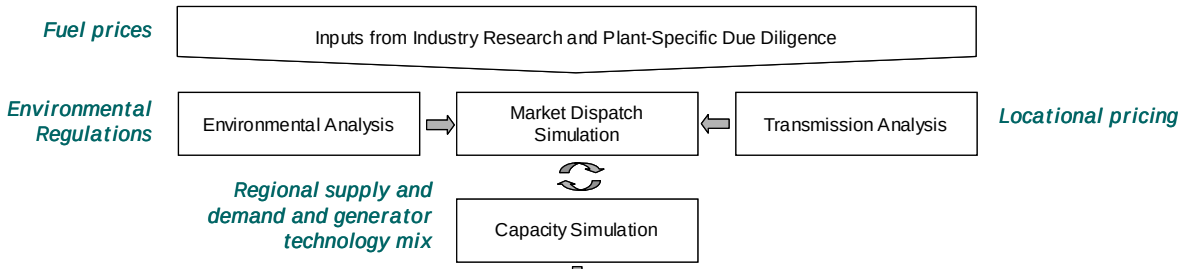
PA's analysis utilizes a market model based on the premise that generators are compensated for more than the marginal cost of energy. PA's approach forecasts additional compensation (above marginal cost) for the going-forward costs of generation (i.e. costs of generation that are not sunk) to maintain system reliability. In a deficit or equilibrium market, this compensation would include the cost of debt and equity required to build the necessary units for system reliability requirements. This compensation could come in the form of energy payments (in spot, forward, and bilateral markets), capacity payments (installed capacity payments (ICAP), unforced capacity payments (UCAP), Resource Adequacy (RA), and bilateral payments), and ancillary service payments.

[14] Actual markets rarely achieve precise equilibrium. Many industries have shown a pendulum of cycling returns, where above-market returns are followed by excess entry resulting in lower returns, followed by under-investment, which in time yields higher returns. While such cycles are often characteristic of commodity markets, the market generally seeks economic equilibrium.

## E.2 KEY COMPONENTS OF THE ANALYSIS

PA employs a variety of models to forecast market prices in regional markets and project the performance of assets. The approach and the types of models used are widely accepted and commonly relied upon in the energy industry to forecast asset cash flows. The key components of the analysis are illustrated in Figure E-1.

**Figure E-1: Key Components of the Modeling Process**




The central components of PA's analysis are the simulation of plant dispatch operations ("Dispatch Simulation" on the diagram) and capacity additions and retirements ("Capacity Simulation"). Multiple inputs drawn from industry research also shape the analysis.

### E.2.1 Environmental analysis (emissions)

Environmental regulations force generators to incur costs to comply with limits on emissions of certain pollutants, generally reducing cash flows. PA uses its proprietary Multi-Pollutant Optimization Model (MPOM) to project the costs of these regulations.

PA's forecast reflects the costs and constraints of a multi-pollutant regulatory scenario, which includes restrictions on sulfur dioxide ($SO_2$), nitrogen oxides (NOx), mercury (Hg) and carbon dioxide ($CO_2$) emissions. In this context, PA projects:

- the optimal timing and type of environmental capital expenditures (given the trade-off between expensive environmentally efficient equipment and higher emissions costs)
- the optimal fuel type for each plant (given the trade-off between cleaner fuel and higher emissions costs)
- emissions cost rates for the pollutants (given volumetric caps imposed by regulation).

MPOM is a model that solves for the optimal market-driven decisions to comply with emissions constraints and maximize cash flows over the long term.

Beyond the near term (when forward prices are used), the prices for NOx and $SO_2$ emissions allowances are outputs of this model based on the current regulations in place. Carbon pricing is derived based on an analysis of proposed legislation. The prices and decisions

associated with all environmental programs are used as an environmental cost in the dispatch of generating units.

### E.2.2 Environmental analysis (renewable energy)

The renewable energy credit (REC) market has emerged as a way for renewable generators to capture additional payments for the green attributes of their energy production. In general, a REC is defined as one megawatt-hour of renewable energy generation delivered to the electric power system. RECs are purchased by load-serving entities, often to satisfy renewable portfolio standards (RPS).

PA projects REC prices based on the additional revenue needed (above and beyond revenues earned from the energy market) for the lowest cost renewable resource needed to meet RPS requirements. Main drivers to the REC price forecast include:

- market energy prices
- transmission constraints
- the type and amount of renewable resources that can be built in a region
- renewable tax incentives
- technology development costs.

PA's REC price modeling approach involves projecting demand for renewable energy based on the projected electricity sales for the load serving entities and the RPS annual goals. For each year of the forecast, a cash flow is developed for renewable resources to determine project revenues and to calculate the REC price sufficient for a renewable project to break even. In early years, transmission limitations restrict the amount of renewable resources that can be added in addition to the amount of planning and construction time required for resources to be brought into service.

The REC forecast is determined by identifying the required REC payment for the marginal technology needed to meet the RPS goal. The identification is accomplished by comparing the renewable supply stack, sorted from low to high cost technologies, to the RPS demand in each year. For most years, wind generation is expected to be the marginal resource and thus set the REC price. In the early years, the REC price reflects current market prices.

### E.2.3 Transmission analysis

Transmission limitations introduce power price disparities within a region, and these price disparities affect cash flows. For favorably located units (for instance, within an area of high demand but limited access to supply due to transmission constraints, such as Southwest Connecticut), these disparities increase gross margins. For unfavorably located plants (for instance, within an area of low demand and minimal transmission access to areas of high demand), these price disparities reduce gross margins.

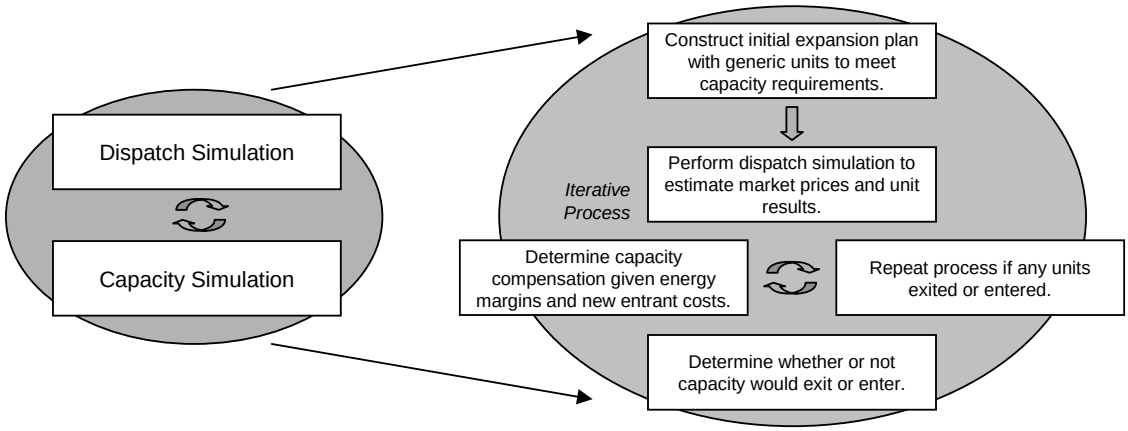
PA employs its transmission expertise and conducts power flow modeling analysis to assess the intrazonal transmission congestion and constraints that a given power generating asset is projected to encounter.

### E.2.4 Dispatch simulation

Power plants are dispatched to generate and sell power when demand justifies the operating costs. Units with low operating costs relative to other facilities are dispatched often; units with high costs are dispatched less frequently. The hour-by-hour interaction of supply and demand determines how frequently and how profitably plants dispatch within a market, and simulating this interaction is a modeling approach that is commonly relied upon in the industry to forecast cash flows.

An iterative process of dispatch and capacity simulation is at the core of PA's methodology. After PA specifies an initial capacity plan to satisfy the load projections, PA's model simulates the behavior of the regional power markets and the corresponding dispatch decisions of assets. PA's model then simulates the decisions market participants would make to add or retire capacity given the performance of the plants. Figure E-2 illustrates the iterative process.

**Figure E-2: Iterative Dispatch and Capacity Simulation**




The dispatch of the regional markets is simulated using MULTISYM™, an hour-by-hour chronological production cost-based dispatch model. Within MULTISYM™, generating units in each pertinent transmission area are modeled individually, taking into account the unit-specific cost and operating characteristics. Units are dispatched in the simulation in the order of economic merit (according to dispatch cost) until adequate generation is brought on line. The cost of the last unit dispatched to meet load requirements sets the power price for that hour.

The products of the dispatch simulation are energy price forecasts for the regional power markets and performance statistics for each of the generating units (such as capacity factors and gross margins).

### E.2.5 Capacity simulation

The remaining steps of the dispatch and capacity simulation (see Figure E-2) relate to the decisions market participants make regarding capacity entry and exit.

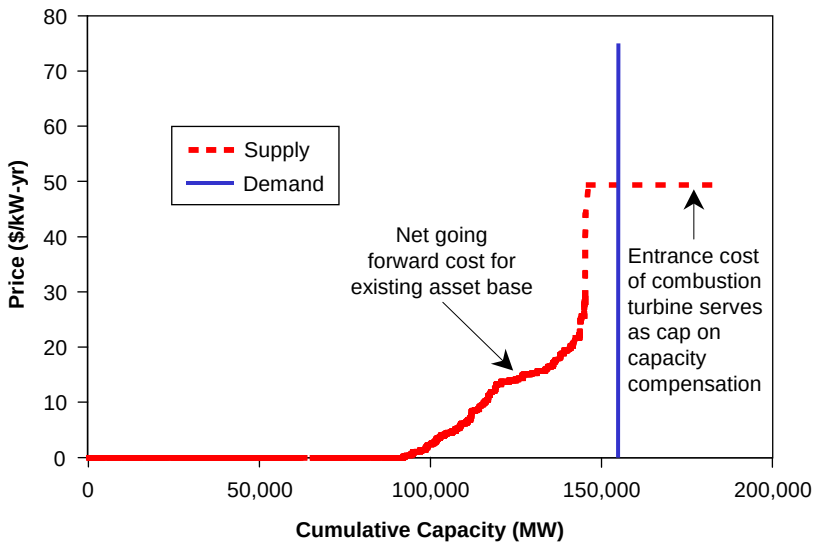
Plants that continue to lose money will eventually be retired. Conversely, market participants who perceive the opportunity for an attractive investment return will undertake to construct new plants. Both of these dynamics will change the power markets over time and affect the earnings prospects for assets.

*a. CAPACITY COMPENSATION SIMULATION*

The difference between the energy margins produced by the dispatch analysis and the going-forward costs drives the amount of additional compensation necessary to motivate generators to provide capacity (PA defines this as capacity compensation).[15]

PA's capacity compensation model assumes that each regional market will retain a sufficient amount of capacity to meet reliability requirements. The intersection between capacity supply and demand determines the rate for capacity compensation, as illustrated in Figure E-3.

**Figure E-3: Example Supply and Demand Curve**




[15] Going-forward costs are the fixed costs that could be avoided with unit shutdown, i.e. the costs exclusive of sunk capital or financing costs.

### *b. CAPACITY ADDITIONS AND RETIREMENTS*

Over the projection period, each regional supply mix changes due to capacity additions and retirements.

- For the near term, capacity changes are based on PA's assessment of public information regarding retirements and additions. PA excludes construction projects that have been announced but not yet financed, permitted, or started.

- For the long term, capacity changes are a function of projected returns. Units that expect to lose money for five consecutive years are retired at the end of the third losing year. New units are added if the projected energy and capacity margins provide an adequate investment return.

The resulting supply mix then becomes the basis for another dispatch model run. This process is repeated until retirements and additions converge, marking the end of the dispatch and capacity simulation process.

## *APPENDIX F: COST OF POWER ASSUMPTIONS*

| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Peak Load (MW) | 132 | 136 | 139 | 142 | 145 | 147 | 150 | 152 | 153 | 155 | 158 | 160 | 163 | 166 | 169 | 172 | 174 |
| Peak Load w 15% Reserve Requirement (MW) | 151 | 156 | 160 | 164 | 167 | 169 | 172 | 174 | 176 | 179 | 182 | 185 | 188 | 191 | 194 | 197 | 201 |
| On Peak Energy (GWh) | 338 | 343 | 349 | 354 | 359 | 364 | 369 | 374 | 379 | 384 | 390 | 395 | 400 | 406 | 411 | 417 | 423 |
| Off Peak Energy (GWh) | 191 | 194 | 197 | 200 | 203 | 205 | 208 | 211 | 214 | 217 | 220 | 223 | 226 | 229 | 232 | 235 | 239 |
| On Peak Energy with 5% losses (GWh) | 356 | 361 | 368 | 373 | 378 | 383 | 388 | 394 | 399 | 404 | 410 | 416 | 421 | 427 | 433 | 439 | 445 |
| Off Peak Energy w 5% losses (GWh) | 201 | 204 | 208 | 210 | 213 | 216 | 219 | 222 | 225 | 228 | 231 | 235 | 238 | 241 | 244 | 248 | 251 |
| Renewable Requirement Case 2&4 | 111 | 113 | 115 | 117 | 118 | 120 | 121 | 123 | 125 | 209 | 212 | 215 | 218 | 221 | 224 | 227 | 230 |
| Renewable Requirement Case 1&3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 209 | 212 | 215 | 218 | 221 | 224 | 227 | 230 |
| On-Peak Energy Prices ($/MWh) | 53 | 54 | 61 | 64 | 66 | 70 | 73 | 77 | 80 | 80 | 84 | 86 | 88 | 89 | 93 | 94 | 98 |
| Off-Peak Energy Prices ($/MWh) | 47 | 48 | 53 | 55 | 58 | 61 | 62 | 65 | 67 | 68 | 71 | 73 | 75 | 76 | 78 | 79 | 82 |
| Wholesale Capacity Compensation ($/kw-yr) (Case 1&2) | 30 | 37 | 39 | 118 | 121 | 123 | 125 | 127 | 129 | 132 | 134 | 137 | 139 | 142 | 144 | 147 | 149 |
| Greenfield Capacity Compensation ($/kw-yr) (Case 3&4) | 112 | 114 | 116 | 118 | 121 | 123 | 125 | 127 | 129 | 132 | 134 | 137 | 139 | 142 | 144 | 147 | 149 |
| Renewable Compensation ($/MWh) | 7 | 6 | 41 | 33 | 33 | 31 | 30 | 29 | 27 | 27 | 25 | 25 | 26 | 27 | 26 | 27 | 25 |
| Transmission plus ancillaries ($/MWh) | 6 | 6 | 6 | 6 | 6 | 6 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 8 | 8 | 8 |
| Case 1 Total Costs ($000) | 36,287 | 38,688 | 43,214 | 58,423 | 61,222 | 64,753 | 67,338 | 70,784 | 73,889 | 81,695 | 84,876 | 88,281 | 91,566 | 94,262 | 98,249 | 101,034 | 105,379 |
| Case 1 Implied Price ($/MWh) | 65.22 | 68.44 | 75.10 | 100.19 | 103.62 | 108.13 | 110.86 | 114.96 | 118.40 | 129.10 | 132.31 | 135.76 | 138.90 | 141.05 | 145.03 | 147.12 | 151.37 |
| Case 2 Total Costs ($000) | 37,055 | 39,385 | 47,944 | 62,326 | 65,076 | 68,436 | 70,993 | 74,323 | 77,261 | 81,695 | 84,876 | 88,281 | 91,566 | 94,262 | 98,249 | 101,034 | 105,379 |
| Case 2 Implied Price ($/MWh) | 66.60 | 69.68 | 83.32 | 106.88 | 110.14 | 114.28 | 116.87 | 120.71 | 123.81 | 129.10 | 132.31 | 135.76 | 138.90 | 141.05 | 145.03 | 147.12 | 151.37 |
| Case 3 Total Costs ($000) | 48,667 | 50,784 | 55,508 | 58,424 | 61,222 | 64,753 | 67,339 | 70,785 | 73,890 | 81,696 | 84,877 | 88,281 | 91,567 | 94,262 | 98,250 | 101,034 | 105,379 |
| Case 3 Implied Price ($/MWh) | 87.47 | 89.84 | 96.47 | 100.19 | 103.62 | 108.13 | 110.86 | 114.96 | 118.41 | 129.10 | 132.31 | 135.76 | 138.90 | 141.05 | 145.03 | 147.12 | 151.37 |
| Case 4 Total Costs ($000) | 49,434 | 51,481 | 60,238 | 62,327 | 65,077 | 68,436 | 70,994 | 74,324 | 77,261 | 81,696 | 84,877 | 88,281 | 91,567 | 94,262 | 98,250 | 101,034 | 105,379 |
| Case 4 Implied Price ($/MWh) | 88.85 | 91.08 | 104.69 | 106.88 | 110.14 | 114.28 | 116.88 | 120.71 | 123.81 | 129.10 | 132.31 | 135.76 | 138.90 | 141.05 | 145.03 | 147.12 | 151.37 |

Peak Load and Energy was derived from 2008 hourly load profile for SSJID service territory supplied by PG&E and growth rates from California Energy Commission California Energy Demand 2010-2020 Adopted Forecast Commission Report and Adopted Demand Forecast Forms, December 2009

Energy prices, capacity compensation and renewable compensation was derived from PA's proprietary modeling as described in Appendix D

Transmission forecast was derived from CA ISO GMC Rates for 2004-2010, Effective 4/1/2010.