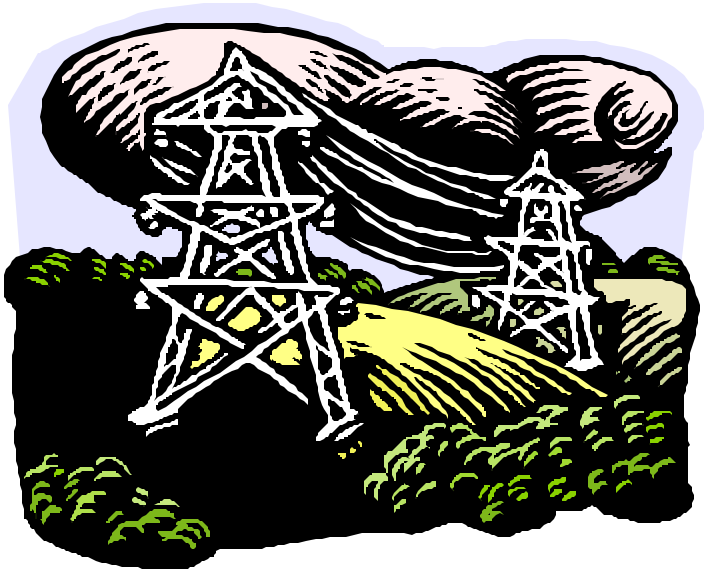


PUBLIC POLICY ANALYSIS

NORTHERN SPHERE MUNICIPAL UTILITY

A decision-making resource for discussions regarding whether the City of Irvine should form a municipal utility to serve future residents and businesses within the Planning Areas 1, 2, 5B, 6, 8A, 9 and 40.

Prepared for City of Irvine

December 2002

ASTRUM Utility Services
462 Stevens Avenue, Suite 308
Solana Beach, CA 92075
(858) 793 5915

Table of Contents

Appendices

I. Executive Summary

The information and analysis presented in this study are designed to provide the City with a broad conceptual understanding of the issues, costs and opportunities associated with creating a municipal electric utility to serve the Northern Sphere Area. This report will be used as a basis for a public policy discussion to explore the full range of possible structures with respect to the ownership, financing, construction, operations and maintenance of utility facilities to provide electric service in the Study Area and includes the following:

- ✓ Identification of stakeholders and their interests;
- ✓ Description of the current electricity market in California;
- ✓ Legal and regulatory issues;
- ✓ Forecast of the electric load and consumption;
- ✓ Conceptual design of the electric infrastructure;
- ✓ Projected capital expenditures;
- ✓ Conceptual description of utility's operations;
- ✓ Comprehensive financial model to project revenues and expenses;
- ✓ Strategic business model to quantify the economics;
- ✓ Sensitivity analysis around key assumptions;
- ✓ Analysis of risks and benefits;
- ✓ Identification of potential partners; and
- ✓ Description of options and associated risks.

Findings

1. The economic evaluation of the proposed electric utility serving the Study Area identified significant potential benefits, including: local control; new revenue sources; significant funds for locally administered energy programs; and ownership of utility assets.
2. The risks inherent in entering a market that would otherwise be served by the incumbent utility include: market fluctuations; regulatory or legislative changes; inability to meet developers' schedule; limited operating experience; and limited resources.
3. A municipal utility could be formed to serve the Study Area within existing legal and regulatory constraints.
4. The municipal utility could be financed with revenue bonds that would place no additional financial burden on the existing residents and businesses.
5. A municipal utility could be managed under alternative operating options.

Study Models

The public policy analysis, compared electric service provided by SCE to a proposed municipal utility. SCE and a municipal utility would provide the following cumulative net revenues through 2025 to the City with the associated risks and benefits.

Electric Service Provided by SCE

Description:

The existing electric service utility provider would expand electric service to the Study Area.

Fiscal Impact:

Cumulative Franchise Fees and Utility User Taxes to City	$ 18.3 million
Cumulative expenses	0
Cumulative net revenues to the City	$ 18.3 million

Risks/Benefits:

RISKS	BENEFITS
• Residents & businesses locate to communities with lower utility costs;	• No increased investment in City resources;
• Delayed development lowers net revenues;	• No indebtedness/capital investment;
• CPUC would continue to establish rates;	• Predictable revenue stream;
• SCE files for bankruptcy.	• More than a century of experience.

Electric Service Provided by a Municipal Electric Utility

Description:

Alternative operating options the City could choose to manage the Municipal Utility include:

- City staff are hired to perform all functions;
- City staff manages contract services to perform all functions;
- City contracts with a third party provider to perform all operating functions and the City would share revenues and risks; and
- City collaborates with another public agency to share revenue/risk in electric service delivery.

Electric Service Provided by a Municipal Electric Utility (continued)

Fiscal Impact:

Cumulative electric revenues	$864.9 million
Cumulative Utility User Taxes to City	9.6 million
Net Borrowings	17.4 million
Cumulative expenses:	
Operating expense (excludes depreciation)	(702.5 million)
Capital expenditures	(46.7 million)
Net Interest expense	(33.5 million)
Cumulative net revenues to City	$109.3 million

Risks/Benefits:

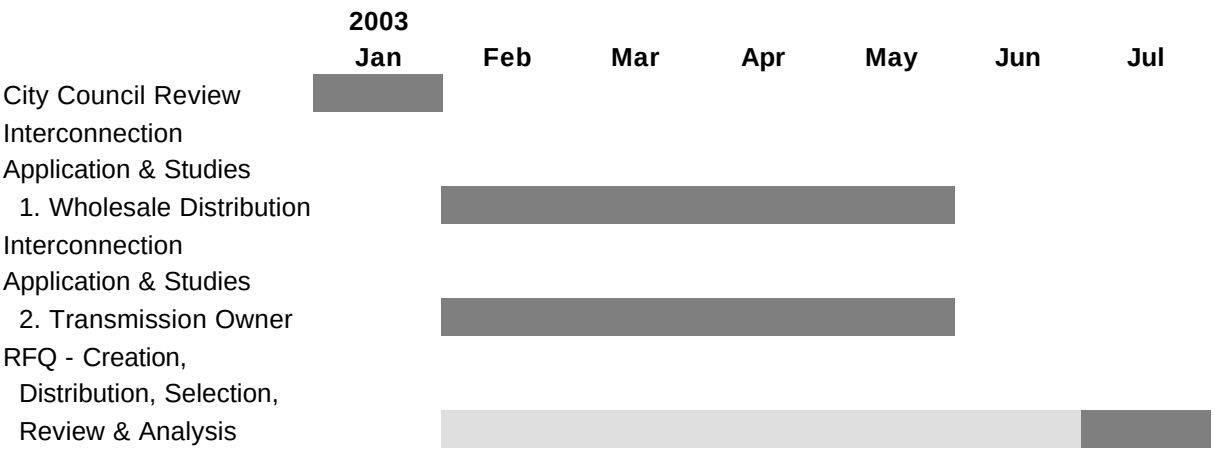
RISKS	BENEFITS
• Higher market energy prices;	• Local control;
• Delayed development lowers net revenues;	• Significant potential revenue stream;
• CDWR and CTC costs lowers net revenues;	• Funds available for locally administered energy programs;
• Larger decrease than forecasted in SCE rates;	• Potential economic development incentive rates;
• Limited City resources / Opportunity costs of projects not completed	• Investment in revenue-producing assets; and
• Customer bypass;	• Select customers to serve
• Third party providers limited experience;	• Lower costs for developers

Comparison Matrix

	Lower Risk to City	Higher Risk to City
Lower Net Revenues to City	SCE Provides Electric Service	
Higher Net Revenues to City		Municipal Utility Provides Electric Service

Recommendation

The public policy analysis suggests there is sufficient stakeholders' common interest to further explore the opportunity to provide municipal electric service to the future residents and businesses in the Study Area. Given the planned development schedule and lead-time to implement an effective business strategy, the next steps in continuing the exploration of a municipal utility strategy is the (i) filing requests for interconnection with SCE; (ii) drafting "Requests for Proposal" for services desire and (iii) preparing the "Line Extension Agreements" with developers. The following timeline summarizes the next steps over the next six months:



II. Introduction

2.1 Background

On February 12, 2002, the Irvine City Council approved a staff request to provide a public policy analysis to explore the feasibility of forming a municipal utility to provide electric service to future residents and businesses in areas of the City that do not currently receive electric service, including the Planning Areas 1, 2, 5B, 6, 8A, 9 and 40 (the "Study Area"). With the approaching annexation of the Planning Areas 5B, 6, 8A and 9, and the planned development of Planning Areas 1, 2 and 40, the City is offered a unique window of opportunity to provide reliable and competitively priced electric service to these future residents and businesses.

In 2001, electric system average rates for customers served by SCE increased 40% and are expected to remain high for a number of years. Effective September 2001, customer choice of electric provider was also suspended. Cities are exploring options to reduce electric rates for their residents and businesses and increase the reliability of services by exercising their California constitutional and charter authority to create a municipal utility in new development areas. Cities that have created municipal utilities are experiencing several advantages: local control; expansion of strategic options for utility services; lower utility rates; enhanced economic development opportunity; lower costs for developers; and funds available for the general fund.

Evaluating options through a public policy analysis of utility services is consistent with the City's strategic goal to promote economic prosperity. Relevant tactical goals in the City's Strategic Business Plan (2002-2007) are:

- Provide the highest quality services to the community at the most cost effective rate;
- Take actions that make it attractive to locate and operate a business in Irvine; and
- Strengthen the City's revenue base.

2.2 Statement of the Issue

This study provides information and analysis to address the public policy question, "Should the City of Irvine form a municipal electric utility to serve future residents and businesses within the Planning Areas 1, 2, 5B, 6, 8A, 9 and 40?"

2.3 Stakeholders and Interests

A wide community of stakeholders with diverse interests would be impacted

should the City provide electric utility service to future residents and businesses. For consideration in the decision making process, the following stakeholders were considered: (i) City of Irvine; (ii) Electric customers outside Study Area; (iii) Electric customers inside Study Area; (iv) Developers; (v) Southern California Edison ("SCE"); and (vi) Irvine Ranch Water District ("IRWD").

Eleven areas of interest were considered:

1. *Local Control.* Governance by residents and businesses through locally elected or appointed officials.
2. *Reliable electric service*. Outage statistics, such as how long customers are without electricity, comparable to surrounding communities.
3. *Competitive rates*. Electric rates comparable to surrounding communities.
4. *Quality of Life*. Increase the attraction for residents to live and businesses to operate in the City through the administration of local energy programs.
5. *Timing*. Have electric facilities in place to meet customers' move-in schedules.
6. *Customer service*. Customer service measures comparable to SCE (call center, outage response, etc.).
7. *Lower costs*. Lower the cost of completing tasks.
8. *Revenue base*. New sources of revenue to either reduce rates and/or transfer funds to the General Fund.
9. *Investment*. Invest in revenue-producing assets.
10. *Safety*. Safety measures (lost-time accidents, etc.) comparable to surrounding electric utilities.
11. *Fiscal Risk*. Assume only reasonable risks that would be commensurate with the associated benefits.

As noted on the matrix on the next page, stakeholders share many interests, such as: local control (City, customers inside and outside the Study Area, IRWD); timing (City, Customers inside the Study Area, Developers, SCE, IRWD); and investment and safety (City, Customers outside and inside the Study Area, SCE and IRWD).

Stakeholders and Interest Matrix

Interest	City	Customers Outside Study Area	Customers Inside Study Area	Developers	SCE	IRWD
Local Control	X	X	X	X		X
Reliable Electric Service	X	X	X	X	X	X
Competitive Rates	X	X	X	X	X	X
Quality of Life	X	X	X	X	X	X
Timing	X		X	X	X	X
Customer Service	X		X	X	X	X
Lower Costs	X	X	X	X	X	X
Revenue Base	X	X	X	X	X	X
Investment	X	X	X	X	X	X
Safety	X	X	X	X	X	X
Fiscal Risk	X	X	X	X	X	X

2.4 Municipal Utility Formation

This study explores a range of possible structures with respect to the creation, ownership, financing, construction, operation and maintenance of a municipal utility necessary to provide electric service in the Study Area. If the City chose to provide electric service, developers could install the local distribution system, ownership could be deeded over to the City, and the City could install the infrastructure to interconnect these facilities to the electric transmission facilities as well as acquire the required power supply.

Strategic Business Goals of a Municipal Electric Utility

The strategic business goals of the utility would be to:

- Provide the highest quality services at the most cost effective rate;
- Meet the developers' approved schedule and implement equitable utility practices and policies;
- Strengthen the City's revenue base; and
- Implement the most fiscally prudent policies and practices.

Why Have Other Public Agencies Pursued Public Power?

There are over 2,000 community-owned or public electric utilities in the United States, including 39 in California, which provide 25% of electric requirements in the State. Fifty percent of these US utilities are comparable by number of customers and 83% by revenues to the City's proposed utility. Communities pursue or continue to maintain public power because of lower electric rates (16% lower than the national average), improved reliability, contributions to the General Fund, and greater local control.

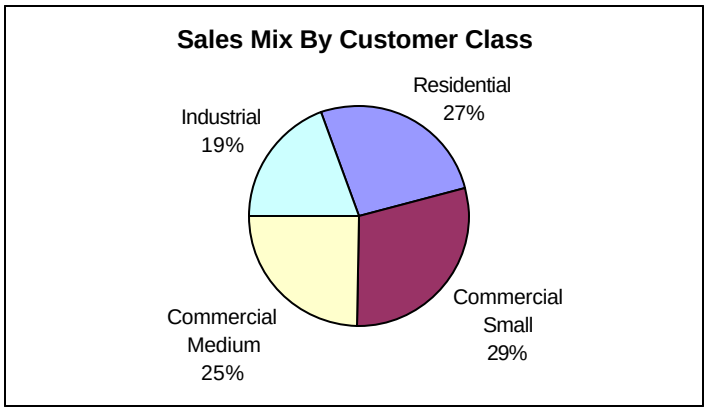
Legal and Regulatory Issues

Many of the legal and regulatory issues related to a municipality providing electric service in areas to be developed have been successfully resolved. Although the California legislature has from time to time considered various proposals that could change the resolution of some of these issues, none have been enacted.

Projected Electric Service

The Study Area is projected to include up to 16,950 residential dwelling units and 17.9 million square feet of commercial, industrial and retail facilities. Development is expected to begin in 2004 and continue through 2024, ultimately serving 19,307 residential and non-residential customers. Based upon historical consumption patterns and industry standards,

the peak demand would grow to 141 MW, and annual electric sales would grow to 534 GWh. This would be equivalent to 27% of the current electric sales in the City and the utility would become the 16th largest publicly owned electric utility in California. As shown on the adjacent chart, the large percentage of sales to and the load characteristics of non-residential customers, makes this a very attractive opportunity for an electric service provider.

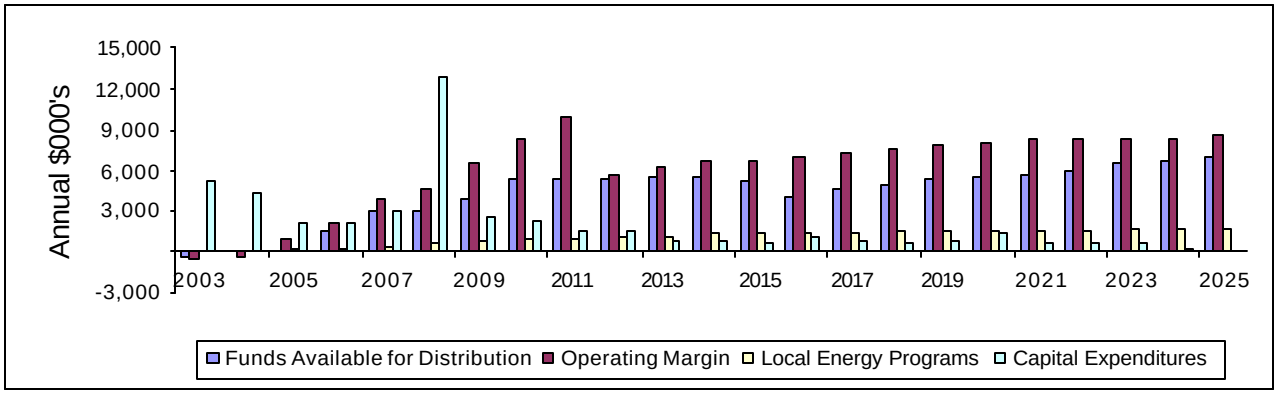


The Strategy: City Ownership of the Electric Infrastructure Serving the Study Area

The strategy would be to own two proposed substations; 3.1 miles of transmission facilities; 126 miles of distribution facilities; and the electric services for the 19,307 customers in the Study Area. Integrating the proposed City-owned substations with the SCE 66 kV sub-transmission system, placing all the transmission and distribution facilities underground, and installing redundant facilities will enhance reliability. The City would invest $46.7 million in utility infrastructure over 24 years.

Operating Revenues and Expenses

SCE's average system rates in the Study Area are forecasted to decline 4.89 cents/kWh (31%). Potential electric revenues were calculated by applying comparable forecasted rates to the annual consumption and load estimates detailed in Appendix E. Expenses include the forecasted price of purchase power, tariff rates, market prices, contractors' bids, industry averages, capital expenditures and replacement reserves.



Economic Evaluation Results

A strategic business model for the period 2003-2025 was developed to quantify the economics of having the City provide electric service to the Study Area. By 2025, cumulative

funds available for distribution could total $99.4 million. In addition funds available for local energy programs, which the City could use to meet energy needs of residents and businesses (see Appendix J), would total $24.2 million. Through 2025, $46.7 million would have been invested in utility infrastructure. The higher capital expenditures in 2003, 2004 and 2008 reflect the estimated cost to construct the interconnection with SCE, two substations and transmission facilities. At 2025, $26.1 million dollars of indebtedness would be outstanding. The present value of the utility's cash flow through 2025 is $46.9 million. Beyond 2025, the present value of the utility's expected cash flow is $55.0 million. The Study was structured to allow the City to evaluate whether to provide electric service to all or a portion of the Study Area.

Operating Structure Options

Several operating structures were considered with respect to the ownership, financing, construction, operation and maintenance of utility facilities. These include:

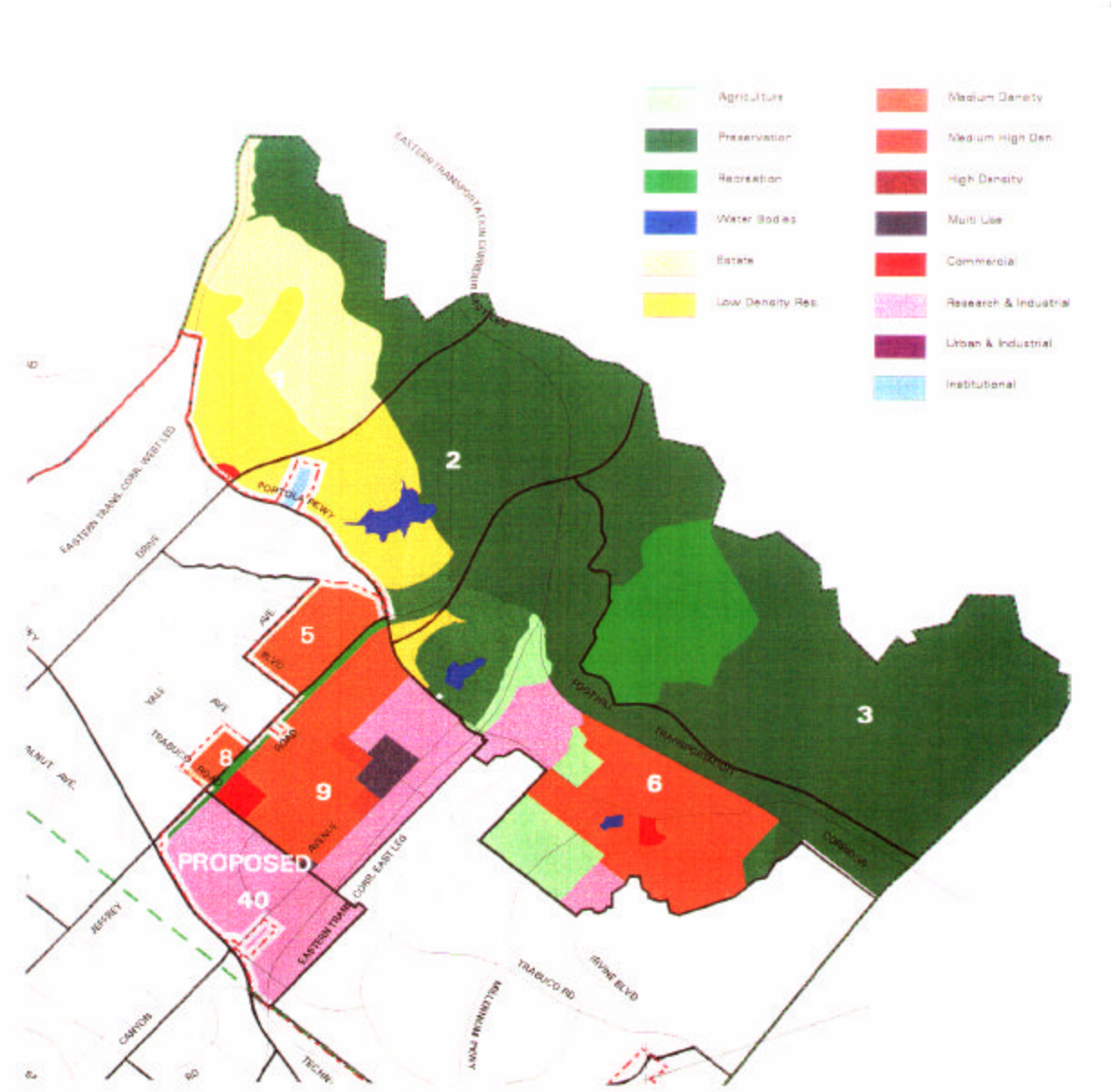
- Status quo, with SCE providing all services;
- City hiring personnel to fulfill all the staffing requirements internally;
- City staff to selectively expand and manage specific contract services;
- Partner with an existing utility to provide specific services; and
- Contract with a third party to provide all resources.

These options vary in their ability to meet the planned development schedule, operating history, costs, revenues to the City, regulatory jurisdiction and associated risks. They are discussed in more detail in Section VIII.

2.5 Consulting Team

Contributors to this Study include: City of Irvine staff; Nossaman, Guthner, Knox & Elliot LLP; Southern California Edison; Irvine Ranch Water District; Butsko Utility Design, Inc.; and Bechard Long & Associates, Inc.

2.6 Map of Study Area



STUDY AREA APPROVED AND PROPOSED LAND USES

III. Public Power Overview

There are over 2,000 community-owned or public electric utilities in the United States today. Many are smaller in size and scope than Irvine's prospective municipal utility. This section describes public power, its characteristics and its benefits as described by the American Public Power Association, the service organization for the nation's community-owned electric utilities. The historical performance of existing public utilities is then presented.

3.1 What Is Public Power?

"Public power" is the term used to describe not-for-profit, publicly owned utilities that are operated by municipalities, counties, states or other public agencies. Most public power utilities are owned by individual communities and regulated by their community leaders. The citizens of those communities, working through local political processes, manage their electric utilities and have done so for decades. Some relevant facts on public utilities include:

- More than 40 million Americans receive electricity from more than 2,000 public power utilities located in every state except Hawaii.
- Public power utilities provide 14.6% of kilowatt-hours sold and 12.9% of revenues from electric sales to end-use consumers.
- About 70% of public power utilities own only distribution facilities; that is, they purchase all of their power requirements and then resell the power to their own customers.

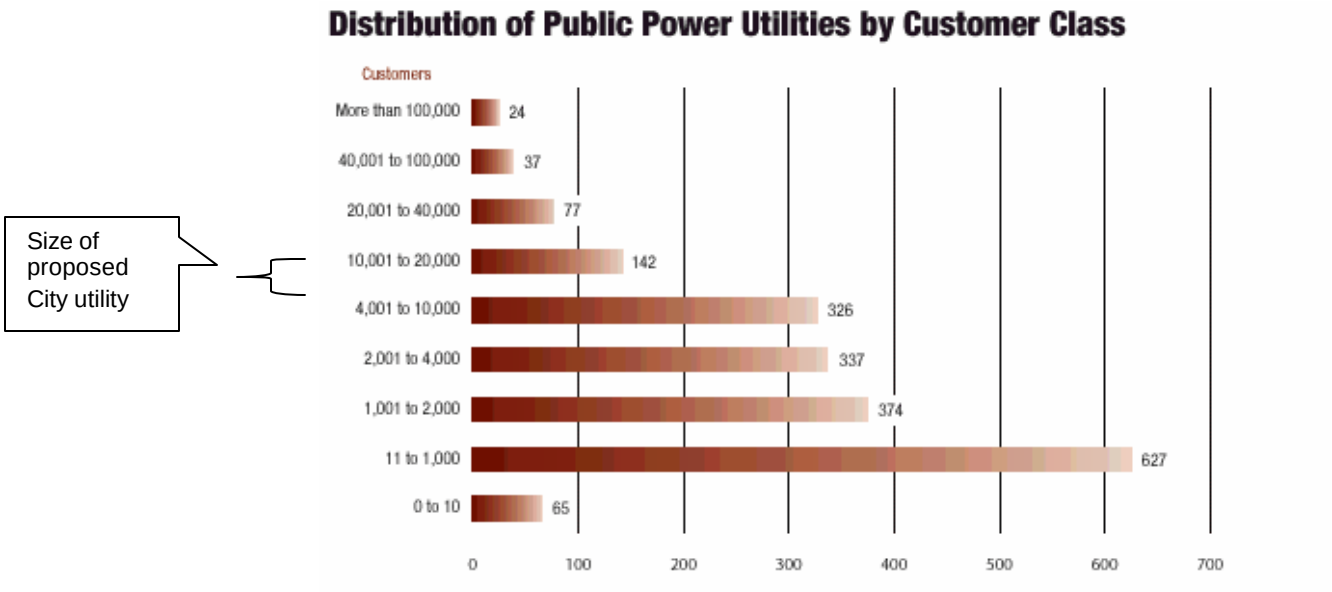
A total of 39 publicly owned electric and gas utilities operate in California with nearly 3 million customers, or 25% of the electric load, and many have been incorporated for more than 100 years. Publicly-owned electric utilities in California include:

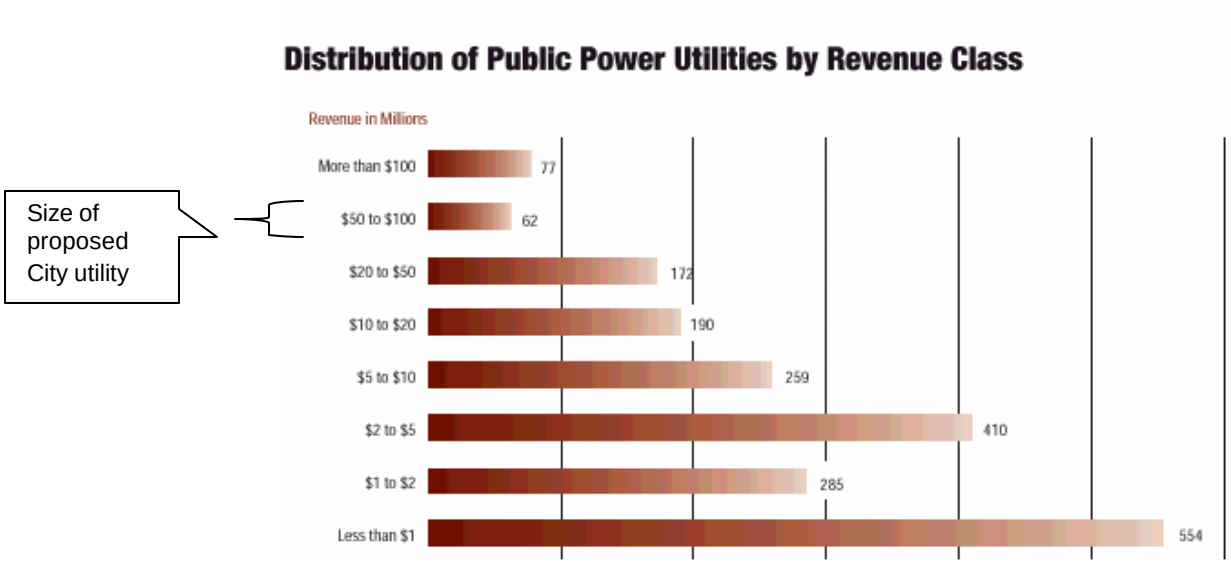
Alameda
Anaheim
Anza
Azusa
Banning
Biggs
Burbank
Colton
Corona
Glendale
Gridley
Healdsburg
Hetch Hetchy W&P
Imperial Irrigation District
Industry
Lassen MUD
Lodi
Lompoc
LA DWP
Merced Irrigation District
Modesto Irrigation District
Needles
Palo Alto
Pasadena
Plumas-Sierra
Redding
Riverside
Roseville
Sacramento MUD
Shasta Lake
Silicon Valley Electric
Surprise Valley
Tuolumne County
Trinity County PUD
Truckee Donner PUD
Turlock Irrigation District
Ukiah
Valley Electric Association
Vernon

A number of cities have also recently passed ordinances and resolutions to authorize the formation of a municipal utility and are in various stages of developing the process. The proposed utility serving the Study Area would be the 16th largest publicly owned electric utility in California.

3.2 Characteristics

The charts of public utilities by number of customers served and revenues are shown below.[1] Note that 93% of the utilities surveyed have fewer than 20,000 customers, and 93% have less than $50 million in annual revenue.

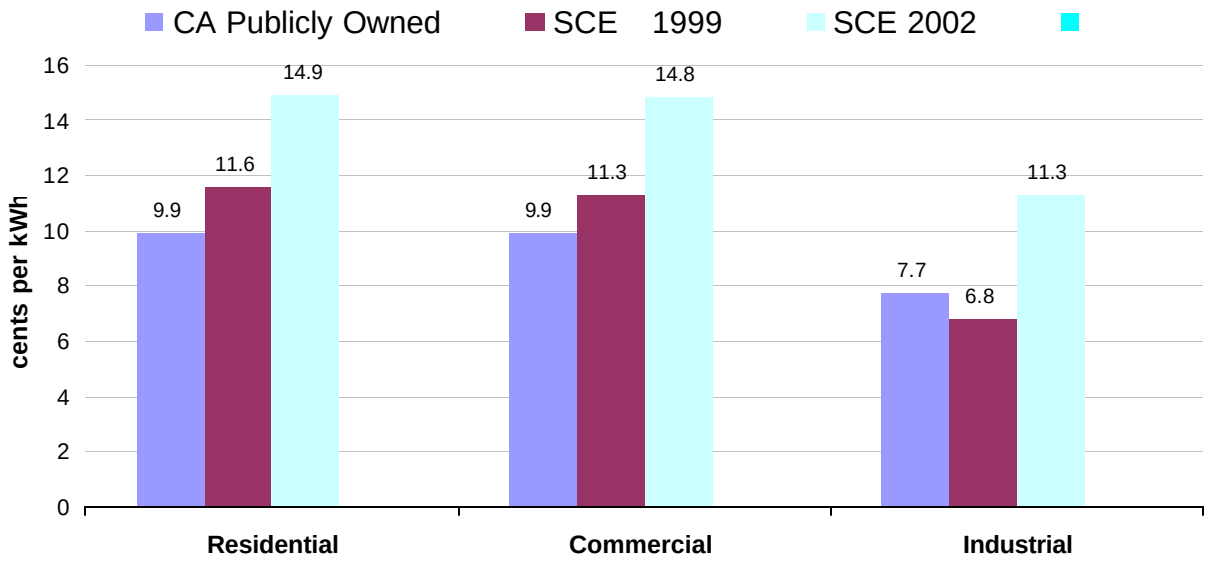




[1] From APPA 2002 Annual Directory and Annual Report.

3.3 Performance

Electric customers measure performance by electric rate paid and reliability of service. The average rates of California publicly owned utilities and SCE are compared below.[2] In 2000, the average rates for residential customers of publicly owned utilities in California were 15% less than those paid by customers of SCE. SCE residential rates are currently more than fifty percent higher than the average public utility residential rate in California.



Public power utilities were able to provide power at lower cost because they

- Can issue tax-exempt revenue bonds for capital expenses;
- Are not for profit and do not pay dividends to shareholders;
- Exempt from income tax payments; and
- Not subject to California Department of Water Resources energy procurement liability.

Measures of reliability are more difficult to develop because important, non-management factors such as geography and weather influence performance. SCE has developed a list of qualified contractors and currently contracts with these entities to perform reliability and emergency services. The proposed Municipal Utility can also follow this business model and contract for required services.

[2] Average rates of California publicly owned are taken from APPA 2000 data.

IV. Legal and Regulatory Issues

Many of the legal and regulatory issues related to a municipality providing electric service in areas to be developed have been successfully resolved. The definitive facts in each circumstance will determine the ultimate outcome of these potential issues. Although various proposals have been introduced in the California legislature that could change the resolution of these issues, none have been enacted into law.

4.1 Authority to Provide Service

Constitutional Authority

Article XI, Section 9(a) of the California Constitution provides broad authority for municipal corporations to establish, purchase, and operate public works for the benefit of their inhabitants. Article XI, Section 9(a) provides:

> A municipal corporation may establish, purchase, and operate public works to furnish its inhabitants with light, water, power, heat, transportation, or means of communication. It may furnish those services outside its boundaries, except within another municipal corporation that furnishes the same service and does not consent.

Statutory Authority

California Public Utilities Code Section 10002 provides that "[a]ny municipal corporation may acquire, construct, own, operate, or lease any public utility." Public Utilities Code Section 10001 provides:

> "Public utility" … means the supply of a municipal corporation alone or together with its inhabitants, or any portion thereof, with water, light, heat, power, sewage collection, treatment, or disposal … transportation of persons or property, means of communication, or means of promoting the public convenience.

City Charter

> Section 200 of the City's Charter provides that:
>
> The City shall have all powers possible for a City to have under the Constitution and laws of the State of California as fully and completely as though they were specifically enumerated in this Charter specifically … It shall also have the power to exercise any and all rights, powers and privileges heretofore or hereafter established, granted, or prescribed by any law of the State, by this Charter, or by other lawful authority, or which a municipal corporation might or could exercise under the Constitution.

Paragraph C of Sec. 6-4-501 of Chapter 5 of Division 4 of Title 6 of the Irvine Municipal Code adopted February 12, 2002, authorizes the City to:

> operate a public utility within or without the present or future corporate limits when necessary to supply the City, or the inhabitants, businesses or lands within the City, or any portion thereof, not then served with electrical utility service, with municipal electrical utility service.

Based upon the relevant provisions of the California Constitution, California Public Utilities Code and City Charter, the City has broad legal authority to acquire, own, construct, maintain and operate the necessary facilities to provide electric service to future residents and businesses.

4.2 SCE Franchise Agreement

Provisions of Franchise

The City has granted an electric service franchise to SCE. It is a non-exclusive franchise to transmit and distribute electricity for any and all purposes. The term of the franchise is indeterminate, subject to the voluntary surrender of abandonment, or until all property actually used and useful in the exercise of the franchise is purchased by voluntary agreement or eminent domain. The franchise may also be forfeited for non-compliance with its terms by SCE.

Franchise Fee

SCE currently collects from the residents and businesses and pays to the City a franchise fee of 1% of the gross annual receipts derived by SCE from the sale of electricity within the limits of the City. The City will continue to receive the annual franchise fees that SCE collects from their existing customers.

A municipality can collect "in-lieu" franchise fees and there is no constitutional or statutory restriction on transfer of fees collected to the City's General Fund. Other California municipal electric utilities do make such transfers. For example, in fiscal year 2001, Alameda Power and Telecom collected and remitted to the City of Alameda $2.4 million in utility taxes. The Utility could continue to collect and transfer to the General Fund such a franchise fee.

Article XIIID of the California Constitution, enacted as Proposition 218 by a vote of the people in 1996, limits the purposes for which "property related fees or charges" may be imposed. However, electric and gas charges are exempted from these restrictions. Section 3(b) of Article XIIID provides:

> For purposes of this article, fees for the provision of electrical or gas service shall not be deemed charges or fees imposed as an incident of property ownership.

In the model, it has been assumed that the municipal electric utility would collect an in-lieu franchise fee of 1% of total revenue.

4.3 Regulation of Utility Services

CPUC Jurisdiction

Under the California Constitution, private corporations and persons that own, operate, manage or control facilities for the production, generation or transmission of heat, light, or power directly or indirectly to or for the public are public utilities and subject to the control of the California legislature. By statute, a "public utility" includes heat, electric and gas corporations. The control and regulation of public utilities in California is vested in the CPUC, which has administrative and judicial powers conferred on it by both the Constitution and the California Legislature.

Municipal Electric Utilities

The CPUC has no jurisdiction over municipally owned utilities unless expressly provided by statute, and the California Legislature has generally not empowered the CPUC to regulate electric utilities owned and operated by municipal or other governmental entities. Examples of statutes that apply to municipal utilities are customer deposits and termination of service.

4.4 Establishing Rates

CPUC Jurisdiction

The City has the authority to establish the rates to be charged for utility services provided by the Municipal Utility. These rates are not subject to review by the CPUC. California courts have uniformly interpreted the constitutional grant of authority to municipal corporations under Article XI of the Constitution to include the power to fix rates charged by municipally owned public utilities.

Governance

State law does not explicitly dictate the governance process to set rates for municipal utilities. The authority to guide the utility can be vested in the city council or an independent elected or appointed utility board. Both forms of governance are accountable to the citizens they serve. In 2001, the American Public Power Association conducted its sixth Governance Survey to determine the type of control government's exercise over publicly owned electric systems. The majority of survey respondents, or 59%, is governed by a city council, while an independent utility board governs the remaining 41%.

Methodology

The legal standard applicable to municipal ratemaking has been articulated in court decisions that require that rates be fair, reasonable, just, uniform and nondiscriminatory. One of the expected guiding principles of the municipal utility is that its rates for electricity will be no greater than those billed by the incumbent utility for comparable services. There is a presumption that rates set by governmental officials are just and reasonable, thereby shifting the burden of proof to any party seeking to prove that the rates are unreasonable or unfair.

4.5 Use of Revenues

As described on page 15 there is no constitutional or statutory restriction on transfer of surplus revenues from a municipal electric utility. Funds could be reinvested in the Study Area for electric rate reduction or could be transferred to the City's General Fund. Other California municipal electric utilities make such transfers. For example, pursuant to the City of Riverside's Charter, the City of Riverside Electric Utility may transfer up to 11.5% of its prior year's gross operating revenues to the City's general fund. In fiscal year 2001, this electric utility transferred 5.8% of gross operating revenues, or $15.2 million to the Riverside general fund.

4.6 Public Benefit Programs

In January 1998, California Assembly Bill 1890 established a public benefits charge on electric retail revenues (2.85%) to be designated for qualifying public benefits programs. Qualifying programs include cost-effective demand side management services to promote energy efficiency and energy conservation, new investment in renewable energy resources and technologies, development and demonstration programs to advance science and technology, and services for low-income electricity customers. Public benefit collections from customers in excess of costs incurred by qualifying programs are deferred to future years. As a municipal electric utility, the monies collected from the public benefits charge could remain in the City to meet the local needs of residential, commercial and industrial customers. Appendix J provides a listing of public benefit programs established in other communities. Appendix J lists public benefits monies ($24.2 million over the planned development period) that would be available to the City.

4.7 Obligation to Serve

SCE has the obligation to serve all electric customers in its service territory. What services and which customers the municipal electric utility serves would be a policy decision for the City.

4.8 Interconnection to the Electric Grid

For purposes of acquiring and receiving electricity, the creation of a utility would require filing an application for interconnection and transmission service with SCE pursuant to

SCE's Transmission Owner Tariff or its Wholesale Distribution Tariff. SCE's Transmission Tariff (§3.18 Eligible Customer) says an entity is eligible for transmission service provided the entity is not prohibited by Section 212 (h)(2) of the Federal Power Act. Because the City is a political subdivision of the State and will own and control electric facilities used to deliver power, the City is clearly not prohibited by Section 212 (h)(2). The Tariff also requires the performance of studies to determine the specific facilities needed to accomplish any interconnection and the cost of such facilities. The facilities needed for the interconnection must be paid for by the entity requesting interconnection with the public utility.

4.9 California Department of Water Resources Energy Procurement Liability ("CDWR")

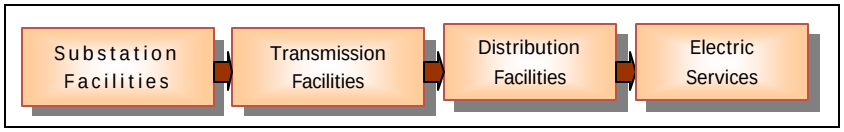
These costs relate to the long-term power purchase contracts that the State executed in 2001. A recent report quantified this energy procurement liability at 2.7 cents/kWh. The recovery of these costs is the subject of current CPUC proceedings. The potential impact of such cost is described in Section 7.3. As described in Section 4.3, the CPUC does not have the requisite legal authority to require a municipal utility or its customers to pay CWDR fees.

4.10 Competitive Transition Charge Liability ("CTC")

These costs relate to uneconomic costs of SCE's generation-related assets and obligations. These costs are currently estimated to be 1.1 cents/kWh and are expected to decline over time through 2025. The recovery of these costs is the subject of current CPUC proceedings. The potential impact of such cost is described in Section 7.3. As described in Section 4.3, the CPUC does not have the requisite legal authority to require a municipal utility or its customers to pay CWDR fees.

IV. Infrastructure Costs

This section analyzes the electric load and infrastructure costs to serve the businesses and residents in the Study Area. As shown on the adjacent block diagram, the City's electric assets would consist of: (i) Two substations (at 66 KV) and interconnection facilities with SCE (at 66KV); (ii) 3.1 miles of transmission facilities (at 66KV); (iii) 126 miles of distribution facilities (at 12 KV); and (iv) Meters and transformers. This economic evaluation reviewed the planned development using land use, tenant profile and absorption information obtained from City Staff, Irvine Company and SCE. The electric load, electric infrastructure and capital costs were then forecasted based upon the planned development and historical consumption data.



The economic evaluation assumes the City would set developers' cost burden equivalent to those formulas described in SCE tariff book, excluding the Income Tax Component of Contribution (ITCC) described in Section 5.4.1. How much of the electric cost the developer pays would be a policy decision for the City.

5.1 Development Schedule

Development Schedule

The electric load, supporting electric infrastructure and capital costs were determined using the following development schedule:

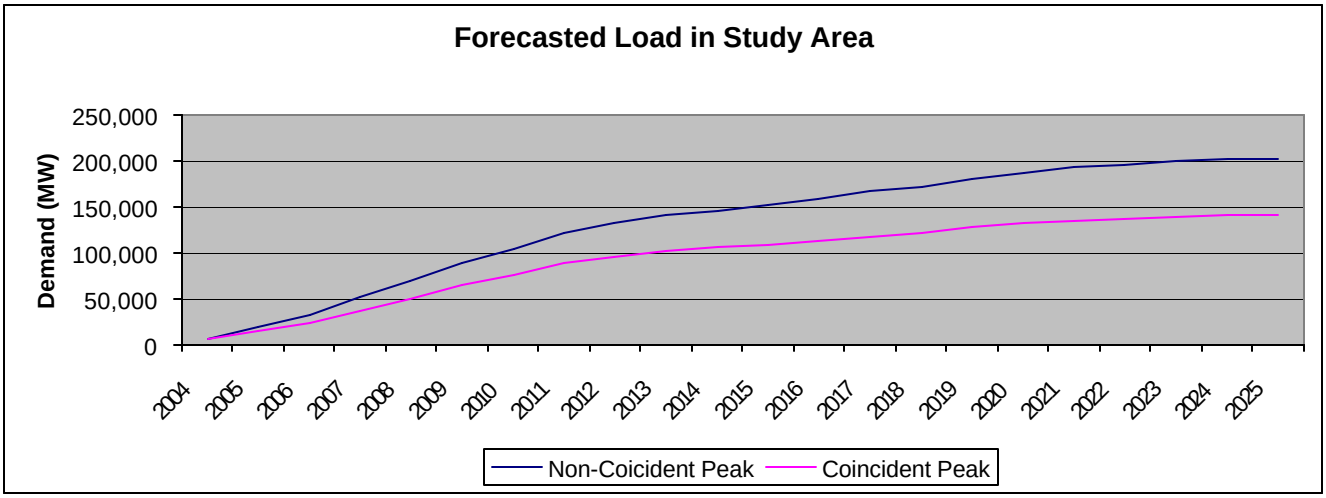
Planning Area	Commercial & Industrial (square ft)	Retail & Schools (square ft)	Residential (dwelling units)	Timing
40	10,000,000	0	0	2004-2011
5B, 6, 8A and 9	6,566,000	1,125,000	12,350	2004-2024
1 & 2	0	200,000	4,600	2004-2011
Total	16,566,000	1,325,000	16,950	

The land use is detailed in Appendix D and summarized in the table below.

	Square Ft.	Customers
Residential		
Detached	**25,255,000**	**8,955**
Attached	**9,915,000**	**5,870**
Apartments	**1,912,500**	**2,125**
Subtotal	**36,362,500**	**16,950**
Non-residential		
Commercial – Small (< 30 K s.f.)		
Commercial Office	**3,574,050**	**1,456**
R & D Office	**3,005,000**	**627**
Retail	**152,250**	**94**
Gas Station	**5,000**	**5**
Commercial – Medium (> 30 K s.f.)		
Commercial Office	**3,174,050**	**55**
R & D Office	**3,005,000**	**47**
Retail	**720,000**	**8**
Restaurant	**32,500**	**8**
Fast Food	**40,250**	**14**
Industrial	**3,807,900**	**40**
Schools	**375,000**	**3**
Subtotal	**17,891,000**	**2,357**
Total	**54,253,500**	**19,307**

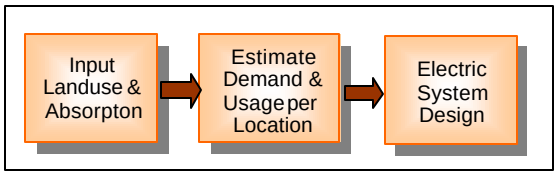
5.2 Electric Load Forecast

Electric load growth in the new development was estimated by applying historical electric demand and usage factors to the planned land use and absorption estimates. By 2024, the non-coincident and coincident peak demands in the Study area were estimated to grow to 202 MW and 141 MW respectively. The load estimate is detailed in Appendix E and illustrated in the chart below.



5.3 Electric Infrastructure Required

The cost to supply electricity to the City's future developments is dependent on the magnitude and location of the electric loads and interconnection facilities. The inputs to determine the capital investments are shown in the adjacent functional block diagram. Redundant facilities have been assumed installed to enhance reliability. The primary components for the load study and planned electric system are the interconnection with SCE, and substation, transmission and distribution facilities. All facilities will be new and the transmission and distribution facilities will be underground. These costs are summarized in Appendix F.



Interconnection

Several existing SCE 66 kV substations, including the Irvine Substation located next to the entry gate of the El Toro Marine Base, currently serve the area. Three 66 kV lines currently loop through the Irvine Substation. The interconnection would connect the City's electric system to SCE and include the required SCE system improvements. The proposed SCE interconnection would be at a proposed City owned substation (the "Trabuco"

substation), located next to the Irvine Substation. This interconnection location was selected for several reasons: (i) It would be integrated into the SCE 66 kV system to increase system reliability; (ii) It would be adjacent to planning Area 40 and any future development at the planned Orange County Great Park, lowering future required infrastructure cost and reducing line losses; (iii) Additional transmission facilities would not be required to interconnect with the SCE facilities, and therefore lower the cost of the interconnection; (iv) It would be several miles from the ISO controlled substation (the Santiago Substation) and lower the cost of the "Wholesale Access Distribution Tariffs"; and (v) The expected available capacity at the Irvine Substation could be sufficient to meet the initial load requirements of the Study Area.

Prior to any interconnection work, SCE would complete a system impact study and Interconnection Facility Agreement to determine the required system upgrades and costs to their existing 66 kV sub-transmission system to accommodate the planned loads in the Study Area. It is expected that the required system upgrades would be completed in two phases. Phase one would tie into the available capacity at the Irvine Substation. The time that is required to complete the interconnection is established by tariff. It may take 10 months and is estimated to initially cost $250,000 (see Appendix F). Phase two is expected to require that SCE increase the existing 66 kV tie line conductors and/or provide additional dedicated 66 kV circuits to the Trabuco Substation. The total cost for the interconnection was estimated at $2 million.

Alternatively, the City can interconnect directly with the California Independent System Operator ("ISO") controlled transmission system (the Santiago Substation), replace the required SCE system upgrades with City-owned facilities and eliminate the "Wholesale Access Distribution Tariff."

Substation

The two proposed City-owned 66-12 kV substations would transform electricity from the transmission (66KV) to distribution voltage and include the:

Name	Location	Description	Costs	Energized
Trabuco	Adjacent to SCE Irvine Sub.	66-12kV	$4.5 million	2004
Sphere	Jeffery Road & Portola Parkway	66-12kV	$2.5 million	2009

The Trabuco Substation would interconnect with the SCE Irvine Substation and serve the load in Planning Area 40 and the initial 9MW load in the Planning Areas 1, 2, 5B, 6, 8A and 9. Two 12 kV distribution lines would be initially installed from the Trabuco Substation to the and

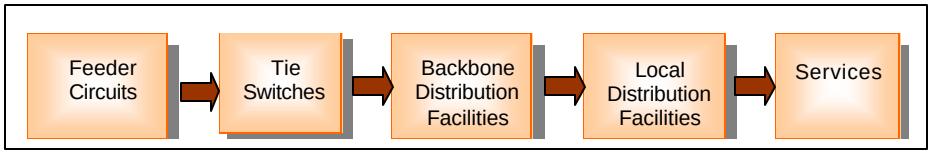
Planning Areas 1, 2, 5B, 6, 8A and 9 to serve the planned load and increase reliability. The cost of these distribution facilities was estimated from the street maps at $88 per foot or $1.4 million. These facilities would be integrated into the eventual distribution system design. The Sphere Substation would have a separate interconnection from the Irvine Substation. Appendix G shows a proposed layout of the substations.

Transmission Facilities

Transmission facilities consist of higher voltage lines (66 KV and above) and deliver electricity from the substation to the distribution facilities. Two City owned 66 kV transmission lines would interconnect the Trabuco Substation and Sphere Substation in 2009. The cost of the 3.1 miles of transmission facilities was estimated from street maps at $6.4 million. These facilities are budgeted for underground placement. If the transmission facilities were placed above ground the costs would be reduced to $2.1 million.

Distribution Facilities

Distribution facilities can deliver electricity from the substation to each end user's electric service. The inputs to determine the capital investments for distribution facilities are shown in the adjacent functional block diagram:



Feeder Circuits and Tie Switches. Feeder Circuits are large-capacity 12 kV capacity lines that deliver power from the substation to the individual non-residential buildings or to the backbone distribution facilities. Tie switches would connect the feeder circuits and backbone distribution facilities. These costs were estimated from the street maps at $44 per foot for feeder circuits and $25,500 for each tie switch, or $10.4 million.

Backbone Distribution Facilities. Backbone distribution facilities connect the feeder circuits to the local distribution circuits. The costs were estimated from street maps at $33 per foot or $5.8 million.

Local Distribution Facilities. Local distribution facilities connect the backbone distribution facilities to the services for residential and small commercial customers. The costs were estimated from the street maps at $21 per foot, less the forecasted developers' contribution, or $3.4 million.

Services. Services include the service connections from the distribution facilities in the street to the customer's site, including conductors, meters and transformers. The cost for services to non-residential buildings ranges from $14,200 to $25,700; costs for residential dwelling units average $370. The costs were estimated from parcel maps and planning documents and totals $11.7 million.

5.4 Infrastructure Costs

The total infrastructure costs required to build out the electric distribution system and serve the Study Area would be $46.70 million. These capital costs are summarized in the adjacent table. The timing of these capital costs, based on the projected land use and absorption schedules, is detailed in Appendix F-1. These capital costs are shared between the developer and utility. Investor-owned utilities have a cost-sharing formula that is prescribed by the California Public Utility Commission. Most municipal electric utilities require that developers pay for all local distribution capital costs.

Total Electric System Infrastructure Costs ($ mil)

Description	Total
Interconnection	$ 2.00
Substation	7.00
Transmission	6.44
Feeder Circuits	9.13
Tie Switches	1.22
Backbone Facilities	5.82
Local Distribution	3.43
Services	11.66
Total Capital Costs	$ 46.70

5.4.1 Developer Cost Burden under SCE

The process begins when the developer provides planning information that SCE uses to design the system and estimate electric infrastructure costs. The developer then executes a line extension agreement with SCE. Under the traditional approach for extending electric service to new developments, a developer provides or advances the cost for the trench, conduit and substructure facilities and then deeds these facilities to SCE. In addition, the developer advances to SCE the estimated cost for cable connection and equipment. SCE then constructs the utility infrastructure. The developer's advances are eligible for refund as electric meters are installed.[3] The refunding formula follows rules on file with the utility's tariff book.

Once the infrastructure has been completed, it would be deeded over to SCE. This contribution is treated as taxable and SCE charges the developers an Income Tax Component of Contribution (ITCC) to cover the estimated liability for the Federal and State income tax. The ITCC is equal to 27% of the value of the infrastructure deeded to SCE. A

[3] In general, capital costs related to site development such as trenching, substructures, etc., are not refundable and are paid for by the developer and deeded over to the utility. Direct utility capital expenditures including wires, transformers, etc., are typically refundable up to a limit referred to as allowances.

portion of the ITCC may be refundable. The ITCC associated with the residential planned developments could be $9.3 million. $ 5.6 million could be refundable to the developer. These amounts do not include the ITCC associated with the non-residential planned developments, which would also result in significant additional ITCC savings.

5.4.2 City Utility Infrastructure Cost

If the City provides electric service to the Study Area, it must invest capital equal to the total electric system cost less the amount paid by developers. The City's estimated capital cost incurred over the 21-year development period is $46.70 million. These costs are detailed by year in Appendix F.

Pro Forma Developer Costs under City ($ mil)

Description	Total
Total Electric System Cost	$ 50.13
Less Developer Paid Costs	3.43
Total City Costs	$ 46.70

Most municipal electric utilities require that the developer pay all costs associated with local distribution facilities ($3.43 million). Under this scenario, the City's capital costs would be $43.27 million.

VI. Operating Revenues and Expenses

Revenues and expenses would consist of forecasted billings to customers in the Study Area and the expenses associated with the cost of power, transmission, distribution, public benefit programs, in-lieu franchise fees, operating cost and depreciation. This section applies the planned land use; tenant profile and absorption information described in the previous chapter to historical consumption indices, tariff rates, market indices, and industry averages. Electric revenue would be based upon the amount of electricity consumed over a period of time applied to the rates that would be established by the City. The economic evaluation assumes those electric rates would be equivalent to those formulas described in SCE tariff book and forecasted over the planning horizon.

Electric revenues were calculated in six steps over the planning horizon by: (i) Determining the historical consumption per square foot by customer class within the City; (ii) Scheduling the planned build-out and expected vacancy factor of structures to be built in the Study Areas; (iii) Calculating the forecasted annual consumption per customer class based upon the first two steps; (iv) Analyzing SCE's load profile data for each customer rate class; (v) Forecasting SCE's electric rates by category for selected customer classes; and (vi) Calculating annual revenues by customer class.

Expenses include the forecasted cost of bulk power, transmission and control area services, wholesale distribution charges, operating and maintenance costs and depreciation. These forecasted costs are based upon the price of natural gas, capacity costs associated with recently completed generating facilities, tariff rates, expected line losses, SCE's facilities, contractor's bid, industry averages, capital expenditures and replacement reserve.

6.1 Existing Electric Service within the City

The chart below compares SCE energy sales within the City to sales within its entire service territory:

	City	SCE System Wide
Customers	69,000	4.5 million
Energy Sales (Million kWhs)	2,000	78,524
Sales to Non-Residential Customers	85%	69%
Avg. Annual Consumption/Customer (kWh)	29,000	17,500
Annual Revenue ($Million)	260	7,000
Average Rate (cents/kWh)	15.8 (adj.)	14.2
Peak Demand (MW)	325 (est.)	17,890

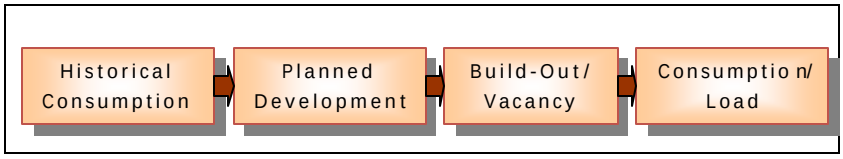
Commercial and industrial customers' facilities consume significantly more electricity per square foot than residences dwellings. As illustrated on the preceding page, the average customer in the City consumes (29,000 kWhs) 65% more electricity than the average SCE customers (17,500 kWhs). The invested capital and operating costs per kWh sold to serve the non-residential consumers are also significantly less than the residential consumers. (For example the forecasted invested capital per kWh to service the residences and businesses in Planning Areas 1 & 2 is 2.8 times the cost to service the businesses in Planning Area 40.) These characteristics make the customer profile in the City a very attractive load for any electric service provider. The percentage of the forecasted non-residential consumption in each of the Planning Areas is as follows:

Planning Area	Annual MWH	% Non-residential	% Residential
40	198,383	100%	0 %
5B, 6, 8A and 9	285,984	64%	36%
1 and 2	*49,338*	*22%*	*78%*
Overall	533,704	73%	27%

6.2 Revenue Projection

6.2.1 Consumption and Demand Data

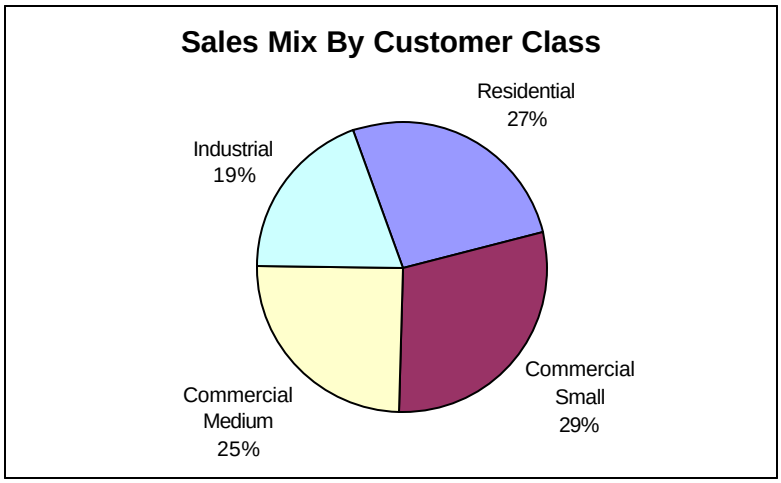
Electric bills are generally based upon the amount of electricity consumed over a period of time. Electric consumption is measured in kWh or MWh. Some customers are also charged for the maximum amount of energy consumed at a particular point in time (i.e., peak demand). Demand is measured in kW or MW. The inputs to likely determine electric consumption and demand are shown in the adjacent block diagram.



Historical consumption per square foot by customer class was calculated in four steps: (i) Analysis of annual electric consumption and peak demand data by customer class from April 1, 2000, to March 31, 2001, and from April 1, 2001, to March 31, 2002; (ii) The number of residential dwelling units by category (detached, attached, and apartments) and the number of square feet of non-residential facilities by customer class (office, retail, industrial, and other) on March 31, 2000, 2001 and 2002; (iii) Calculation of historical consumption per square foot per residential dwelling unit by category and non-residential facility by customer class; and (iv) Comparison of these calculations to standard units of electricity consumption

by customer class in a comparable climate zone.

The development planned for the study area includes 13 customer classes. The forecasted consumption and peak demand per square foot were applied to the planned development to compute the annual consumption and demand data (see Appendix E). The annual consumption for each customer class was then reduced by the annual build-out schedule and expected vacancy factor. The 13 customer classes were also grouped into four "rate classes" (residential, small commercial, medium commercial, and industrial). The percentage of electric sales to each rate class is reflected in the adjacent chart.



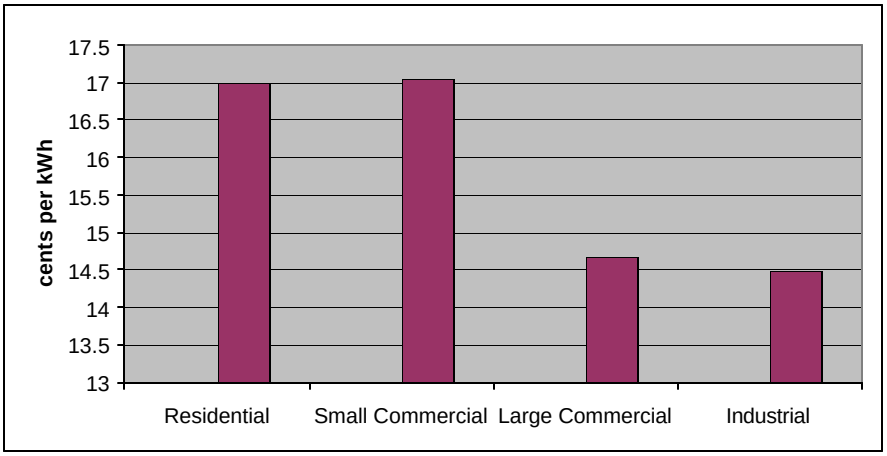
The planned number of customers, consumption and demand profile over the build-out are summarized below:

Table 6.2 – Planned Customers, Consumption, and Demand Profile

		2010			2017			2025	
Description	**Cust**	**Sales (MWHs)**	**Demand (KWs)**	**Cust**	**Sales (MWHs)**	**Demand (KWs)**	**Cust**	**Sales (MWHs)**	**Demand (KWs)**
Residential									
Detached	3,960	39,340	26,187	6,830	72,820	45,364	8,955	98,314	59,688
Attached	2,750	14,968	13,014	4,600	27,208	22,061	5,870	36,412	28,468
Apartments	630	1,920	1,733	1,365	4,364	3,754	2,125	7,066	5,844
Total Res. Cust.	7,340	56,229	40,934	12,795	104,392	71,178	16,950	141,792	93,999
Commercial – Small									
Office	909	50,563	16,861	1,296	75,497	23,497	1,456	85,138	26,126
R & D – Office	430	43,915	12,972	575	61,155	16,838	627	66,319	18,090
Retail	40	1,702	494	67	2,814	835	94	3,925	1,177
Gas Station	2	116	24	3	173	37	5	289	61
Total Com Small	1,381	96,295	30,352	1,941	139,640	41,207	2,182	155,672	45,454
Commercial – Medium									
Office	39	26,418	8,789	51	37,615	11,669	55	41,322	12,680
R & D – Office	32	37,203	10,990	43	51,809	14,265	47	56,184	15,326
Retail	4	10,310	3,204	6	20,621	4,806	8	30,931	6,408
Restaurant	2	409	102	5	1,023	256	8	1,644	412
Fast Food	5	930	259	10	1,859	519	14	2,594	724
Total Com –Med	82	75,271	23,345	115	112,927	31,515	132	132,675	35,549
Industrial									
Industrial	16	43,073	10,213	32	80,319	19,672	40	99,305	24,275
Total Industrial	16	43,073	10,213	32	80,319	19,672	40	99,305	24,275
Schools									
Schools	1	852	598	3	3,407	2,992	3	4,259	2,992
Total Schools	1	852	598	3	3,407	2,992	3	4,259	2,992
Total	8,820	271,719	105,443	14,886	440,686	166,564	19,307	533,704	202,270

6.2.2 Rates

Under a municipal utility the ability to set rates resides with the City. The economic evaluation assumes that the City's rates are equal to the comparable SCE rate tariff. The rates for generation, transmission, distribution, public purpose and other were computed for each

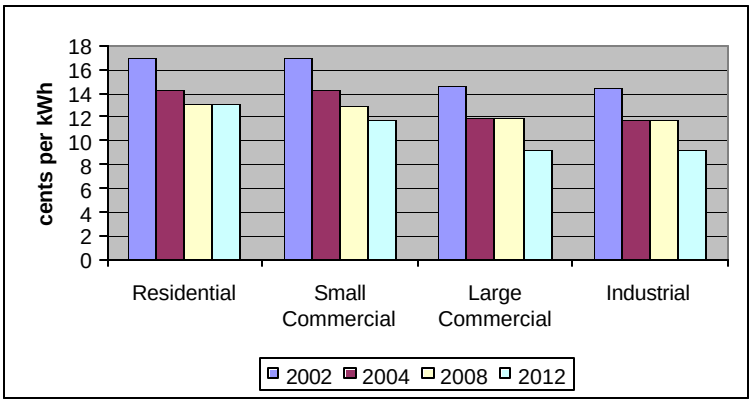


customer class. The chart on the preceding page summarizes the current SCE weighted average rate for each category within the Study Area.

6.2.3 Change in SCE Rates

The California Energy Commission Draft Report "2002-2012 Electricity Outlook Report," issued in February 2002 and revised in July 2002, forecast that SCE's current system average rates would decline by 3.06 cents/kWh by 2012.

This economic evaluation included in this Study decreased current rates by 4.89 cents/kWh in 2012, with changes in 2004, 2008 and 2012. The decrease in 2004 reflects SCE's expected rate decline. The decrease in 2008 reflects the elimination of the payment for the Rate Reduction Bonds. The decrease in 2012 reflects the elimination of the rate increases imposed in 2001, such that rates would be equivalent to the rate freeze approved in 1996. The adjacent chart summarizes the impact of these SCE rate changes.



6.2.4 In-Lieu Franchise Fees

The City has executed a franchise agreement with SCE. This agreement provides that the franchise payment that is collected from SCE customers in the City will not be less than 1% of gross annual receipts derived from the sale of electricity within City limits. SCE also collects a utility user tax equal to 1.5% of revenues, subject to specific limitations, from non-residential customers. In-lieu franchise fees are included in revenues and expenses. The utility user tax would be additional revenues and operating expenses.

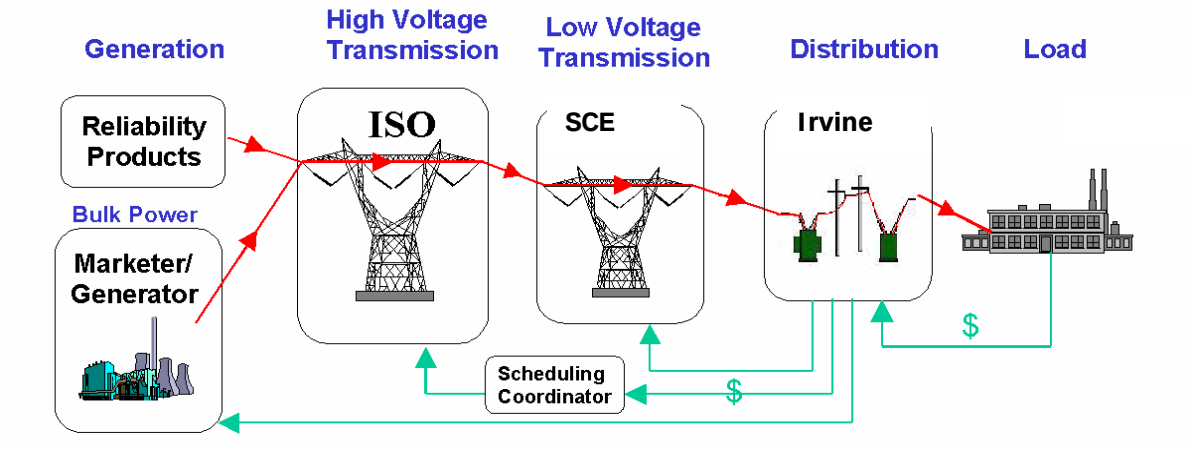
6.3 Expense Projection

6.3.1 Conceptual Plan

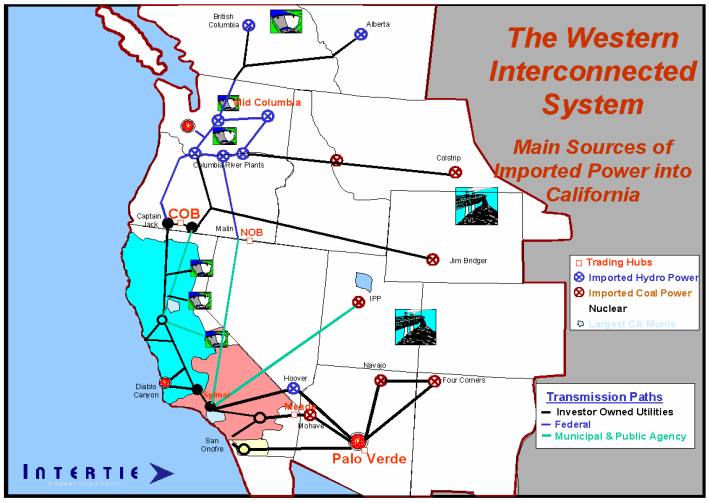
The City could buy power from a generator or power marketer and arrange for high-voltage transmission from the Independent System Operator ("ISO") grid and secure low-voltage transmission from SCE. The City could either take delivery from the ISO-controlled substation (Santiago) in the City or SCE would provide transmission service from the Santiago Substation to the 66 kV Irvine Substation and the City's interconnection point at the

proposed Trabuco Substation. To meet reliability criteria required for prudent utility practice, the ISO automatically purchases reliability generation products on the City's behalf. A scheduling coordinator (hired by the City) would schedule and account for all power flows. These functions are illustrated in the chart below:

Open Transmission Access and Competitive Generation Options



The business processes required to provide retail electric service have been greatly facilitated by deregulation. Transmission service can now be bought on a non-discriminatory and open access basis. Federal deregulation also created competitive power markets in the four interconnected regions of North America. The Western Interconnected System (see adjacent map), the region to which the City-owned distribution system would be connected, is composed of electrical systems spanning 14 Western states, parts of Canada and Mexico. The City can access generation from any plant located in the region (typically through power marketers).



Parties and Required Contracts

The City could execute several underlying agreements prior to providing retail electric service.

- Power Supply Agreement: A supply of electric energy ("wholesale energy") would be purchased in the wholesale market from a generator, power marketer or utility. The

term, delivery point, quantity and price would be specified.

- ISO Agreements: The City would interconnect with the ISO-operated grid (via SCE) and make arrangements necessary for the ISO to recognize the City's delivery points as recipients of wholesale energy and to read its meters for settlement purposes.
- SCE Transmission and Interconnection Agreement: Pursuant to SCE Transmission Owner Tariff (*"SCE TO Tariff"*) or its Wholesale Distribution Access Agreement (*"WDAT"*), the City will pay SCE for transmission service. The City would need to submit an application for interconnection and execute an interconnection agreement requesting that SCE interconnect its system to the City's interconnection facilities. The "SCE TO Tariff" spells out the interconnection process.
- Scheduling Agreement: The City's interconnection and service to future developments is considered a Control Area. To meet its control area obligations, an ISO-certified scheduling coordinator will need to undertake daily scheduling, dispatching and energy accounting services on behalf of the City. As shown by the arrows in the prior chart, the Scheduling Coordinator pays the ISO on behalf of the City for reliability products and high-voltage transmission.
- Retail Service Agreement: The City would purchase power using the above contracts to supply the total electric load requirements of the residents and businesses within the new developments.

6.3.2 Power Supply Cost

The cost of power to the City has three components: bulk power, transmission rates, and control area services. These unit costs over the planning horizon average $67.5 per MWh and are detailed in Appendix J.

Bulk Power

To meet the power needs of its customers, the City could solicit bids from wholesale suppliers. The resulting contract(s) could specify delivery location, load requirements, and duration. The power costs in the financial model are based on the price of natural gas and the capacity costs associated with recently completed generating facilities. The price of natural gas accounts for 65% of the cost of power. The price of natural gas applied to the model over the planning horizon was $4.13/mmbtu, which is 25% greater than the historical cost of gas over the past ten years. The resultant cost of power was $46 per MWh. (The California Energy Commission Draft Report "2002-2012 Electricity Outlook Report" assumed that gas prices would be $3.05-$3.25/mmbtu in 2002 and would escalate annually by 2%.)

The economic evaluation included additional costs of $10 per MWh to shape the power supply to the specific load of the City's demand.

Transmission Services

Bulk power could be transported from the generator's source of power over the ISO-controlled High Voltage (HV) grid and the SCE-controlled Low Voltage (LV) grid. The total transmission cost is the sum of the HV Access Charge, the LV Access Charge, Congestion Charges, and losses through each system.

Control Area Services

While the ISO controls transmission access to California's HV grid, the bulk of ISO costs are incurred in managing power flows and maintaining system reliability. These services are referred to as "control area services." To serve the City's load, control area services are required to synchronize and match the City's load with the Bulk Power Supply and to procure the necessary reliability products to meet WSCC reliability standards. In this analysis, we divide control area service costs into three general cost components:

- Grid Management Charge: Consists of the Control Area Service Charge, the Inter-Zonal Scheduling Charge and the Market Operations Charge;
- Ancillary Services (A/S) Capacity: Regulation, Spinning, Non-Spinning and Replacement Reserves; and
- Real Time Energy: Supplemental Energy, Imbalance Energy, Excess Energy, and Unaccounted-for-Energy Settlement.

6.3.3 Operating and Maintenance Expenses

The estimated cost of operating and maintaining the electric facilities system includes the costs to: (i) Operate and maintain the substation, transmission and distribution facilities; (ii) Provide customer service, customer accounting, and meter reading services; (iii) Provide administrative services, engineering and resource management services; and (iv) Create a replacement reserve for the substation, transmission and distribution facilities. Compared to industry averages, the proposed utility's new facilities that are placed underground are more reliable and require less maintenance. These savings will be somewhat reduced by the initial smaller economies of scale. The estimated costs per customer were based upon (i) Contractors' bids and industry averages ($209 per customer); (ii) Survey of smaller utilities in the Energy Information Administration Form database ($273 per customer); and (iii) The adjusted annual cost for a comparable California municipal electric utility ($450 per customer.) The economic evaluation used $440 per customer. The costs were allocated among the three planning areas based upon the capital investment, number of customers and revenues.

6.3.4 Depreciation

The capital investment of the substation, transmission and distribution facilities was depreciated over 35 years.

VII. Economic Evaluation

A strategic business model was developed to quantify the economics of having the City provide electric service to new residents and businesses in the Study Areas over the planned 21-year build-out. The model included the following annual data by planning area: (i) Revenue calculation by customer class; (ii) Required capital expenditures to serve the planned development; (iii) Expenses for purchase power, transmission and distribution charges, operating and maintenance expenses, and depreciation; and (iv) Debt service. This section presents the results of the financing plan that combines the project's annual capital costs, revenues and expenses. A list of the assumptions used in the model is provided in Appendix L.

7.1 Financing Plan Assumptions

The financial model assumed that the City could issue revenue bonds to finance the initial capital expenditures and start-up costs. The bond issuance could also finance the debt service reserve and costs of issuance. Revenues received from providing electric service are the sole source of paying the debt service on the revenue bonds. The cash balance could provide working capital equal to one month of billed revenues.

The financing plan assumed that the bonds could have a 30-year term and be issued at a tax-exempt rate of 5%. Residents in the City would not have an obligation to pay the debt, as they could with general obligation types of bonds. The return on available cash could be reinvested at 3%. Based upon the financing plan (see Appendix B), $46.5 million could be borrowed over the first eleven seven years. At 2025, $26.1 million dollars of indebtedness would be outstanding.

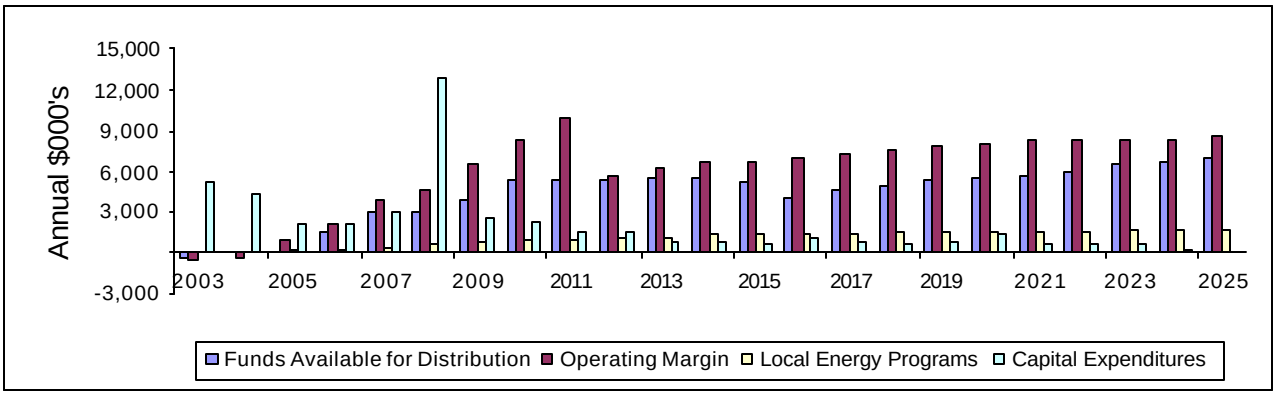
7.2 Financial Plan Pro Forma

The financial pro forma projects that the proposed electric utility serving the Study Area can provide the following benefits over the planned development schedule (2003-2025):

- $99.4 in "Funds Available for Distribution"
- $24.2 million in local energy programs. This money can be used for many public purposes, including assistance to lower income tenants and energy conservation, etc. (see Appendix J).
- $46.7 million in electric utility assets.
- $8.6 million annually in operating margin, beginning in the 22nd year.

The timing of net cash flows, operating margin, local energy programs and capital

expenditures is shown in the chart below.



7.3 Sensitivity Analysis

In addition to the economic evaluation above, several scenarios were also modeled to determine the sensitivity of the results to changes in key inputs. The sensitivity analysis varied the following inputs:

1. *Energy Costs*. The price of natural gas was increased 10%, with no change in the billed tariff.

2. *CTC Liability.* A Competition Transition Charge, as discussed in Section 4.10, of 1.1 cents per kWh and declining over time through 2025.

3. *CDWR Energy Procurement Liability.* A charge, as discussed in Section 4.9, of 2.7 cents per kWh would be assessed through 2011.

4. *Phased Development.* The land use development was delayed 50%.

Table 7.3 – Sensitivity Analysis: Impact on Changes in Key Inputs ($ in thousands)

		Sensitivity Impact ($ million)			
	Study	Higher Energy Prices	CTC Liability	CDWR Liability	Phased Development
Net Change through 2025					
Funds Available for Distribution	$99.432	$ (22,614)	$(5,790)	$(32,261)	$(11,083)
Net Present Value	46,903	(11,117)	(3,134)	(24,037)	(8,436)
Capital Expenditures	46,696	-	-		(2,691)
Local Energy Programs	24,195	-	-		(3,231)
Terminal Value	55,035	(5,437)	-		

Other inputs that could significantly add to the valuation include:

- Additional developments such the proposed Orange County Great Park, where infrastructure investments are already planned as discussed in Section 5.3
- Delays in SCE forecasted rate decreases, as discussed in Section 6.2.3
- Future SCE general rate cases to increase non-energy rates. (SCE pending increase includes a proposal that would allow "cost of business" increase on an on-going basis in subsequent years.)
- Impact of increased energy prices on SCE's rates.
- Faster development than forecasted.

7.4 Benefits and Risks

The public policy analysis suggests there is sufficient stakeholders' common interest to further explore the opportunity to create a municipal utility in the Study Area. To assist in this discussion, this study qualitatively and quantitatively describes the benefits and risks listed below.

Table 7.4 Benefits and Risks

Benefits	Risks
Local Control	Delayed development
Significant potential revenue stream	Higher energy prices
Enhanced economic development	Exit fees assessed
Funds available to administer local energy programs	Delay in installing the required 2003 infrastructure
Investment in revenue producing assets	Larger decrease than forecasted in SCE's rates
Can determine which customers to serve	Changes in legislation
Lower costs for developers	Third-party provider may have limited operating history
	Customer bypass
	Customers lobby for lower electric rates
	Limited City resources

To reduce the scope and management of planned activities, one alternative that the City may also consider is to serve only a subset of the Study Area. For example, only Planning Area 40 or only non-residential customers.

VIII. Operating Options

8.1 Qualified Contractors Available in the Marketplace

To lower operating costs, utilities have consistently used qualified contractors to perform work previously performed by employees. Utilities also provide services to other utilities. Listed below are several illustrative examples:

1. SCE formed Edison Utilities Services to offer construction, operations and maintenance services to municipal utilities. SCE sold Edison Utility Services in 2000.

2. SCE personnel read the water meter for the Irvine Ranch Water District.

3. Pouk & Steinle, Inc., an affiliate of Montana-Dakota Utilities Company, provides design, construction, maintenance and repair services for electric substation, transmission and distribution facilities in Southern California and elsewhere. They currently provide services, including 24-hour emergency services, to SCE and the municipal utilities in Anaheim, Colton, Industry, Pasadena and Riverside.

4. Butsko Utility Design, Inc., provides utility planning, design and management serves for electric distribution facilities within SCE's and San Diego Gas & Electric's service territories.

5. Applied Metering Technologies, Inc., located in Whitter, California, provides meter installation, calibration, maintenance, programming, communications installation, and meter reading services.

6. Irvine Ranch Water District has offered to provide the following services: (i) Customer service; (ii) Meter reading, customer billing and accounting; (iii) Engineering and planning; (iv) Construction management; (v) Field operations; and (vi) Power supply management. These services are outlined in Appendix K.

8.2 Operating Options

To assist in the decision-making process regarding which ownership, financing, construction, operation and maintenance of utility facilities to select, described listed below is a list of suggested criteria options.

Criteria

Eight criteria were identified to compare operating options:

1. *Timing*. To meet the planned development schedule for the proposed interconnection, substation and initial distribution facilities would be designed and constructed in 2003. Beginning in 2004, customer meters would be installed. The cumulative growth in planned capital expenditures and customer additions is:

	2004	2009	2014	2019	2024
Capital Expenditures	21%	69%	84%	93%	100%
Customers	2%	38%	67%	84%	100%

2. *Flexibility*. Capital and operating work requirements will vary due to unplanned activities (reported outages); spot activities (installation, turn-on and turn-off of electric meters); activities over a designated time period (installation of the transmission facilities in 2009); recurring activities (reading electric meters, customer billings and cash collections); and daily activities (customer service, load forecasting). Some activities will cease (building the proposed substations), and other activities will grow (reading customer meters).

3. *Expertise*. Design, construction, maintenance and management of the electric infrastructure requires years a highly educated and experienced staff and administration as well as effective supervision.

4. *Operating History.* Entity has specific experience and independent references for work proposed.

5. *Costs*. Capital and operating costs include the cost of labor, materials and equipment and the related productivity and economies of scale.

6. *Fund Available for Distribution.* A municipal electric utility can transfer surplus revenues to the General Fund and/or reduce electric rates.

7. *Regulatory Issues*. CPUC generally has no jurisdiction over municipally owned utilities. The specific facts would determine whether the CPUC has jurisdiction over a third party that provides all services.

8. *Service Delivery.* Service delivery, and the accountability and responsibility for the delivery of electric services, varies with each scenario.

9. *Risks*. As described in Table 7.4.

Operating Options

As describe below, these options vary in their ability to meet the planned development schedule, operating history, costs, revenues to the City, regulatory jurisdiction and associated risks.

Status Quo: Southern California Edison.

SCE serves 4.5 million customers, employs 12,600 employees, invested $11 billion in transmission and distribution facilities and maintains 4,900 transmission and distribution circuits, and has more than a century of experience. SCE has the resources and expertise to expand its existing electric infrastructure to safely serve the Study Area as required. Changes in electric rates would continue to be approved by the CPUC, and the City would receive the franchise fees and utility user tax described on page 30. If SCE's electric rates exceed those outside its service area, prospective residential, commercial or industrial customers may choose to locate in communities that currently offer lower costs. The City would not: (i) Receive any additional revenues; (ii) Administer local energy programs; (iii) Own the utility assets; (iv) Lower the costs of operations; or (v) Incur any additional risk.

Municipal Utility.

Only City employees or a combination of City and contract employees could operate the municipal utility. Given the planned investment in utility infrastructure in 2003 and the City's lack of experience in operating an electric utility, it would be unlikely that sufficient time exists for the City to meet such staffing requirements. As an alternative, qualified contractors are available in the marketplace. The City could, as the City does today, hire contractors (including SCE) to complete specific tasks. Contractors have the employees, equipment and expertise to meet the planned work schedule. The City would need to retain contract managers to oversee these functions. The City would receive the benefits and be subject to the risks listed in Table 7.4.

Other electric municipal utilities and public agencies also have the resources and expertise to share selected resources to supply the required services. Depending on how the relationship is structured, the City would receive the benefits and be subject to the risks listed in Table 7.4.

A third-party operator could also provide services to the municipal utility, and the City

would receive a negotiated franchise fee. It would be expected that the contract fee would be less than the revenues available from a municipal utility. The provider's resources, expertise or experience may not be comparable to SCE. The specific facts would determine whether the CPUC has jurisdiction over a third party that provides all services. A third-party provider could not issue tax-exempt debt and would be subject to federal and state income taxes. The City could issue tax-exempt debt if it owns the system and the operating agreement meets the Internal Revenue Services management contract rules. It would also be expected that the City would continue to be subject to most of the risks outlined in Table 7.4.