MWD
METROPOLITAN WATER DISTRICT OF SOUTHERN CALIFORNIA

INFORMATION

- **Board of Directors**
  Business and Finance Committee

July 10, 2007 Board Meeting

9-3

Subject

Cost of power for the California and the Colorado River Aqueducts

Description

The Business and Finance Committee requested that staff provide information on Metropolitan's cost of power for the California and the Colorado River Aqueducts. The cost of power is a significant part of Metropolitan's overall cost structure, constituting almost 20 percent of total expenditures. The cost of power to move water on the State Water Project (SWP) and the Colorado River Aqueduct (CRA) is an important component of imported water supply costs. This report addresses costs, but other issues, including greenhouse gas emissions, are also important aspects of the transport of water.

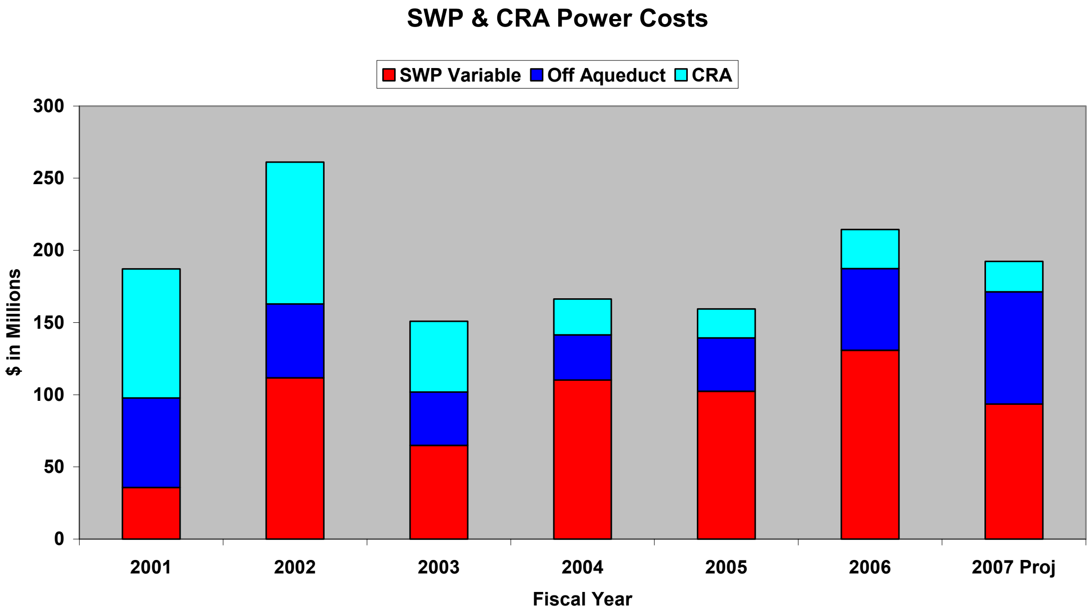

Figure 1: Metropolitan's CRA and SWP Power Costs, $ in Millions

As shown in Figure 1, Metropolitan's total cost of power associated with moving water has increased since 2003. There are two important reasons for this. First, the cost of wholesale power has increased over time, and is now approaching costs last seen in 2001. Second, Metropolitan is using more of its SWP supply.

Figure 2 on the next page shows the average cost per acre-foot to move water on the SWP and the CRA. Costs are relatively low on the CRA because Metropolitan has secured very low-cost, hydroelectric and operational contracts through 2017 that can move approximately 780,000 to 800,000 acre-feet annually. Beyond that amount, Metropolitan relies on the market for supplemental purchases. Because Metropolitan is experiencing low diversion levels on the CRA, the existing, low-cost contractual resources are all that is necessary to meet pumping requirements.

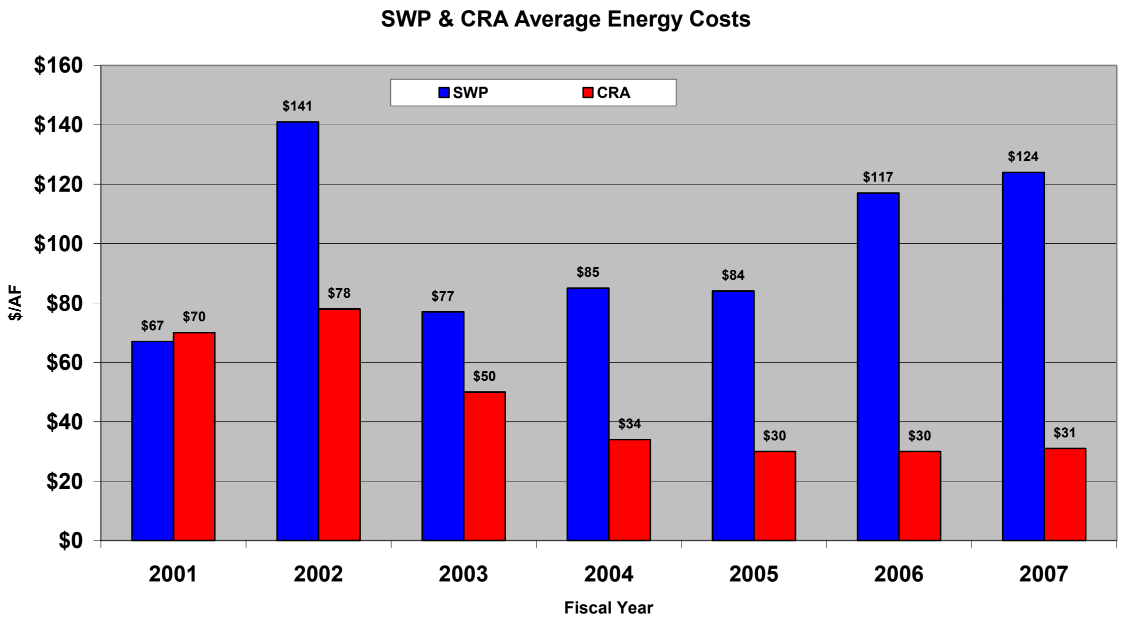

Figure 2: Metropolitan's CRA and SWP Average Energy Costs, $ per acre-foot

The SWP system has a higher average energy cost per acre-foot. The SWP requires 50 percent more energy to deliver an acre-foot than the CRA. The SWP also uses low-cost hydroelectric and recovery resources, but they only meet about 50 percent of the SWP energy needs in an average water year. The SWP relies on the wholesale market and contractual resources with market price risk exposure for as much as 30 to 35 percent of its needs, using other contractual resources to fill in the difference. It is this exposure to the wholesale energy market and the increased energy requirements on the SWP that result in higher average energy costs.

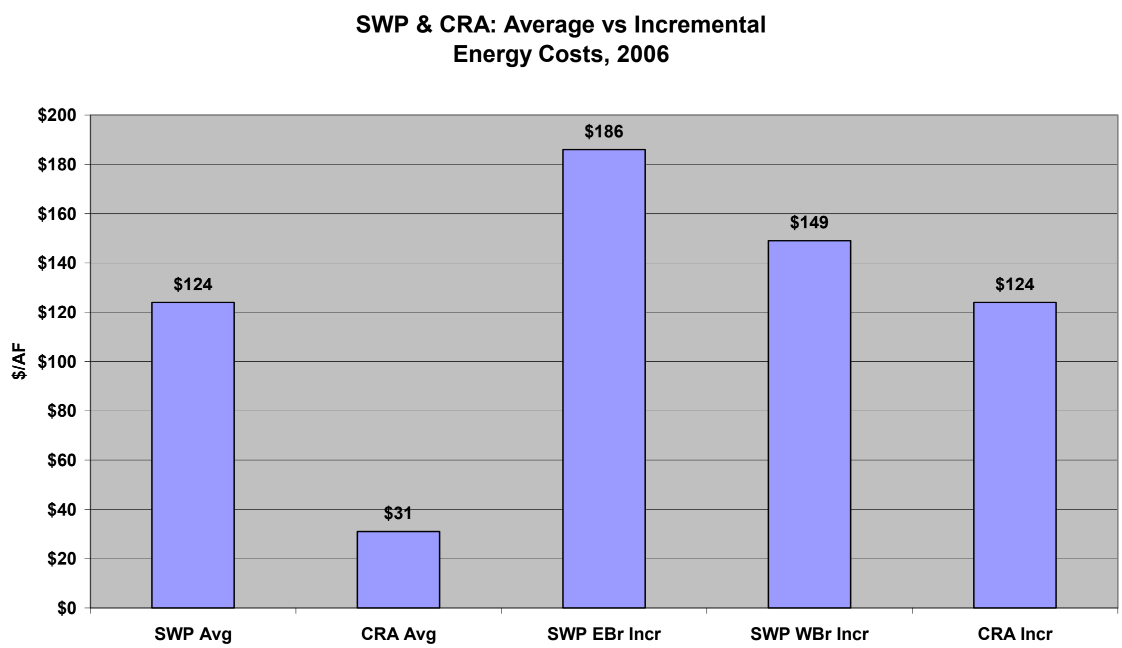

Figure 3: Incremental versus Average Costs, $ per AF

On an incremental basis, the difference between an acre-foot delivered on the SWP and the CRA appears quite different. Because of the nature of the cost sharing among contractors on the SWP, in 2006 the incremental cost to move an acre-foot on the SWP would have been $186 per acre-foot on the East Branch and $149 per acre-foot on the West Branch, compared to an incremental cost of $124 per acre-foot on the CRA. The CRA is still less expensive than the SWP, but not by a factor of 4 times, as the average costs would suggest. Rather than saving approximately $90 per acre-foot by shifting deliveries from the SWP to the CRA, the difference in 2006 was only $25 to $60 per acre-foot, depending on whether the water is delivered on the east branch or west branch of the SWP.

Even though it costs more to deliver an acre-foot of water on the SWP versus the CRA, whether on average or incrementally, the average energy cost on the SWP is still reasonable when compared to the California wholesale energy market and well below what SCE and PG&E charge their largest customers (see Figure 4).

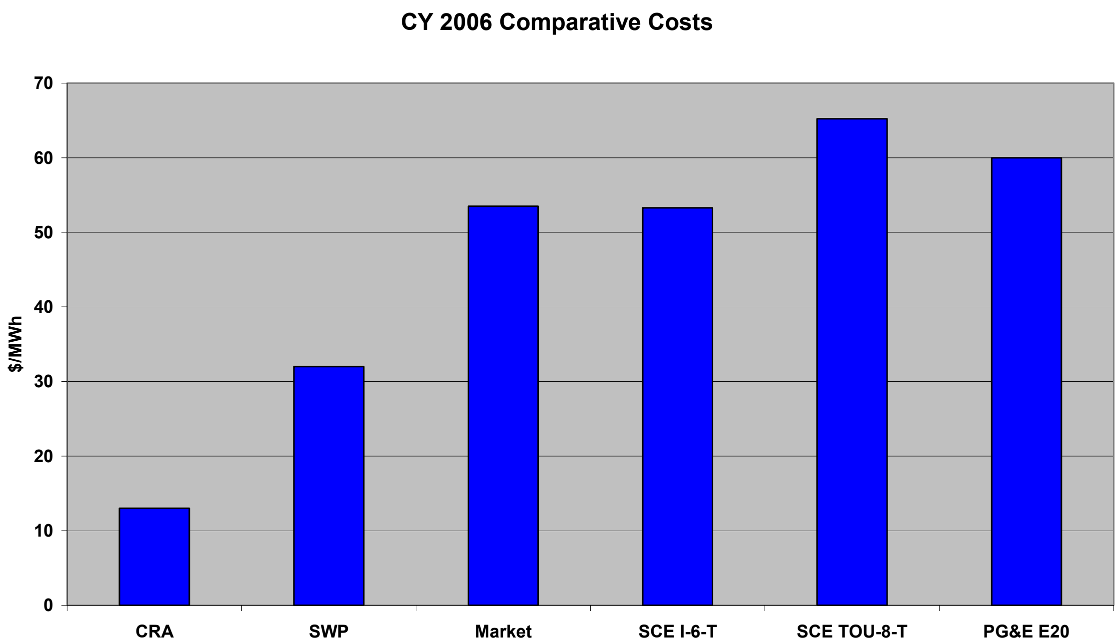

Figure 4: Calendar Year 2006 Comparative Costs, Average $ per MWh

Going forward, staff will continue to monitor issues that will affect power supply costs on the CRA and the SWP and investigate and propose potential approaches to mitigate costs. Identified risks include:

- Contract risk: 2017 contract terminations for the Boulder Canyon Project (Hoover) and the SCE Service and Interchange Agreement. Changes to Metropolitan's CRA power supply portfolio and performance obligations due to changes in terms and/or non-renewal could potentially have significant upward cost impacts on Metropolitan.
- Market risk: fuel and market price risk due to significantly changed Western wholesale energy markets. As described in Attachment 1, the Western wholesale energy markets have undergone profound changes, and are now far more vulnerable to severe price spikes and price volatility. The upward trend of wholesale energy prices combined with high levels of market price volatility result in a need for Metropolitan to evaluate ways to manage these risks, including the use financial as well as physical products.
- Operational risk. Recent examples include pumping restrictions at the Banks pumping plant due to environmental and endangered species issues. Potential impacts on the CRA may be realized as well due to such things as Quagga mussel control. These unplanned events will continue to have negative impacts on Metropolitan's power costs by limiting operational flexibility.

- Greenhouse gas emissions reductions and renewable resource development. The state of California is taking a leadership role in reducing greenhouse gas emissions. A significant contributor to greenhouse gas emissions is the electricity industry. In a 2005 report, the California Energy Commission concluded that the water sector in California is the largest user of energy in the state, accounting for 19 percent of all electricity consumed in the state and 30 percent of non-power plant related natural gas use. Metropolitan and the SWP currently utilize clean, sustainable hydroelectric generation, but Metropolitan and the Department of Water Resources will need to investigate economically reasonable opportunities to reduce greenhouse gas emissions and develop cost-effective renewable energy resources.
- Hyatt-Thermalito relicensing and contractor litigation. DWR's federal license to operate the Oroville Complex—Oroville Dam, Hyatt Power Plant, Thermalito Power Plant, and Thermalito Pumping-Generating Plant, and ancillary facilities—expired January 2007. Relicensing is critical because these facilities generate power used by the SWP to move water to contractors and keep pumping costs low. Proceedings are under way at the Federal Energy Regulatory Commission to approve the continued operations at the Oroville Complex. Not all parties are satisfied with the proposed settlements, and a risk exists that the cost to contractors of relicensing the Oroville Complex increases. Additionally, litigation has been initiated by a coalition of contractors challenging the allocation of costs and benefits from the Oroville Complex, which could increase the cost of the SWP to Metropolitan and other contractors south of the Tehachapis.

Attachment 1 presents a more detailed discussion of the requested overview of power costs on the California and Colorado River Aqueducts.

Policy

Metropolitan Water District Administrative Code Section 4200: Regional Water Management

Fiscal Impact

None

7/3/2007
Brian G. Thomas *Date*
Chief Financial Officer

7/3/2007
Jeffrey Kightlinger *Date*
General Manager

Attachment 1 – Analysis of Power Cost of California and Colorado River Aqueducts

BLA #5427

Cost of Power for California and Colorado River Aqueducts

Background

This report focuses on the cost of power to pump water on the California (State Water Project) and Colorado River Aqueducts. It first provides an overview of the wholesale energy market in California and how that market has changed, and examines how that structural change has affected Metropolitan's major supply sources.

Prior to 2003, wholesale energy prices in California were relatively low, with the exception of the "energy crisis" period of June 2000 through May 2001. Figure 1 presents an overview of wholesale energy prices delivered to Southern California.

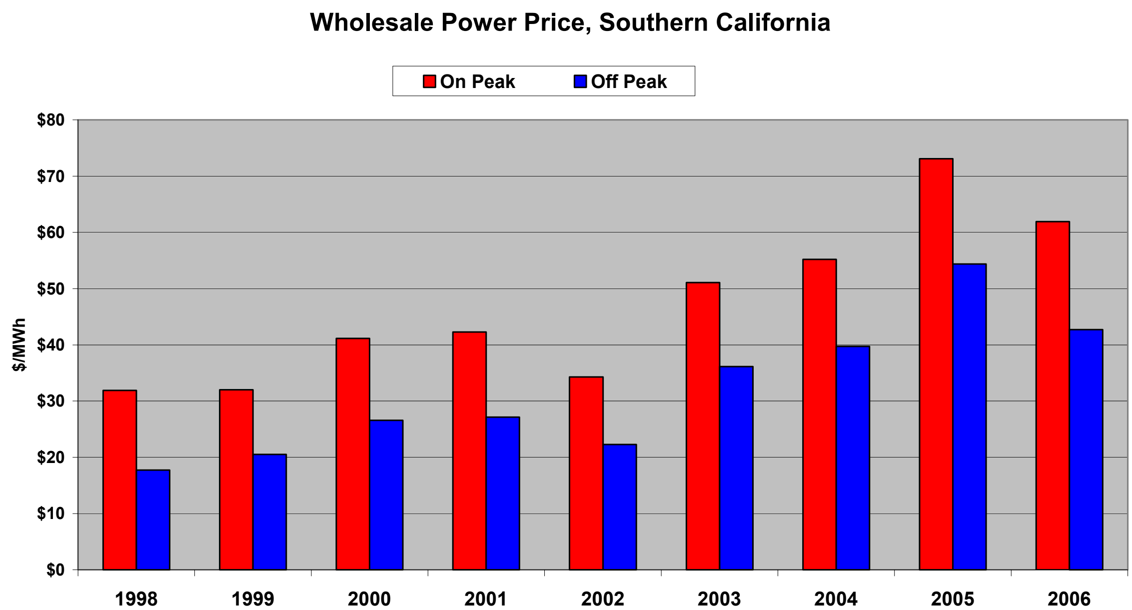

Figure 1: Wholesale Power Prices, Southern California, 1998 through 2006

In 1998, when the California Independent System Operator began operations, energy prices during "peak"[1] periods averaged about $32 per megawatt-hour, while non-peak prices averaged about $19 per megawatt-hour. Beginning in 2003, the wholesale energy markets in California and the United States began demonstrating significant periods of price volatility, culminating in the doubling of peak period electricity prices by 2005. The increase in electricity prices and volatility is due to many factors, including:

- No meaningful generating capacity was added in California after the 1980's until 2001, due to safety concerns with nuclear power and emissions concerns with coal.

[1] For purposes of this report, on-peak is defined as the hours from 7:00 am through 10:00 pm (16 hours inclusive) every day except Sunday and holidays; all other hours are off-peak.

- Of the 13,800 MW of generating capacity added in California since 2000[2], the vast majority has been natural gas-fired, as this is the only fuel that meets California's strict air emissions requirements. Natural gas plants are easier to site and less capital intensive than nuclear, coal and renewable technologies. Other states saw the amount of gas-fired generation developed increase, too. According to Western Energy Coordinating Council data, natural gas-fired generation accounts for approximately 54 percent of the generation mix in the California; of the generation owned by Independent Power Producers in California, about 81 percent is natural gas-fired[3].
- In the 1990's, natural gas was cheap—averaging $1.80 to $2.20 per MMBtu in California—and concurrent with the increased use for generation, residential heating demands grew, particularly in the Northeast, which switched to natural gas from propane and heating oil. Residential heating and power plant demand are extremely sensitive to changes in weather.
- While residential heating and power plant demands for natural gas have increased, industrial demand, which is insensitive to weather, has fallen. Industrial users could typically shut down operations during periods of price spikes to alleviate sharp upward price movements; their decreased demand has taken away that market protection.
- At the same time US demand for natural gas increased, US production matured and actually started to decline.

The result is a tightening of natural gas supplies. Natural gas and electricity are particularly subject to wide price swings as demand responds to changing weather. Inventories are of limited aid in dampening price spikes because natural gas users typically do not maintain large inventories of gas on site, and the options for storing electricity are few and expensive, such as pumped storage, reservoirs, and idle capacity. Shipping low-cost supplies to areas where prices are high may not be feasible because of limited capability on the transmission networks connecting suppliers to load. Limited storage capacity and the lack of cheaper alternative supplies from other areas or resources (coal or nuclear generation that is idle) can cause prices to soar in areas where demand increases suddenly.

To the extent that prices vary because of rapid changes in supply and demand, often associated with severe weather, such as droughts, hot weather, and hurricanes, or nuclear or coal plant outages, energy price volatility allows markets to allocate scarce supplies to their highest value uses, but at the price of financial pain to whoever is buying.

Figure 2 shows the day-ahead price for natural gas delivered to Southern California beginning May 2003 through March 2007. Natural gas prices began showing increased variability in 2003. Each year subsequent, volatility can actually be seen to have

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[2] California Energy Commission Report, *2005 Integrated Energy Policy Report*, November 2005, CEC-100-2005-007-CMF, pp. 50-51.

[3] Western Energy Coordinating Council, *2005 Information Summary*, July 2005, pp. 6-7. "California/Mexico" adjusted to exclude Comision Federal de Electricidad, a 1,900 MW system in Northern Baja California with 1,070 MW of IPP generation.

increased, particularly in the last quarter of 2004 and 2005. This is due to concerns over adequate physical storage volumes and expectations that extreme cold weather events would negatively impact the physical deliverability capabilities of production and transportation facilities.

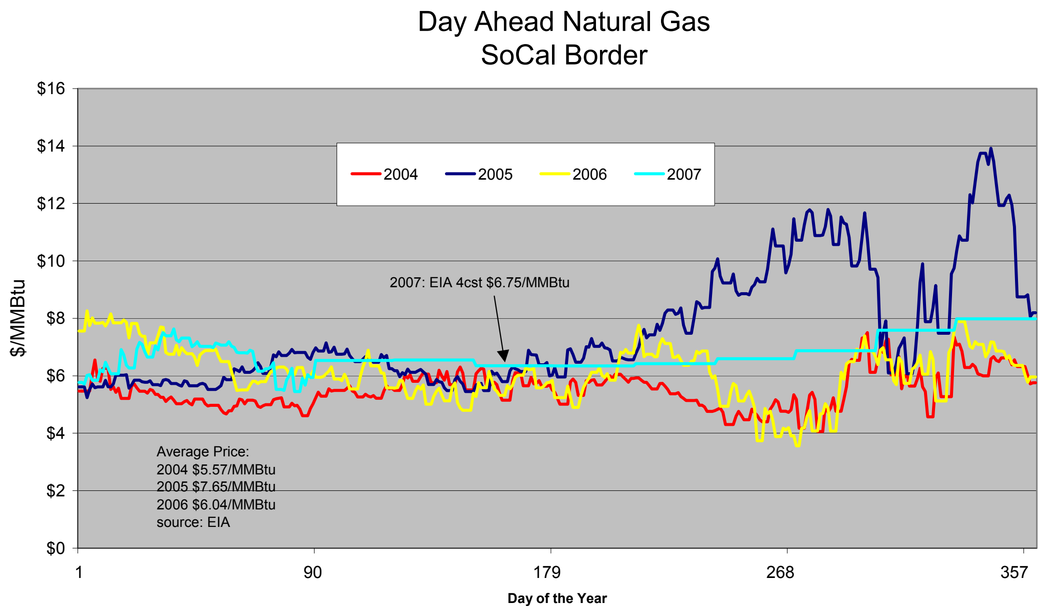

Figure 2: Day Ahead Natural Gas Prices, $/MMBtu at the "SoCal Border"

Gas-fired generation is now the marginal resource in California and it often sets the market price. Therefore, the natural gas and electricity markets are often tightly correlated, and an increase in natural gas prices is immediately reflected in current and future electricity prices.

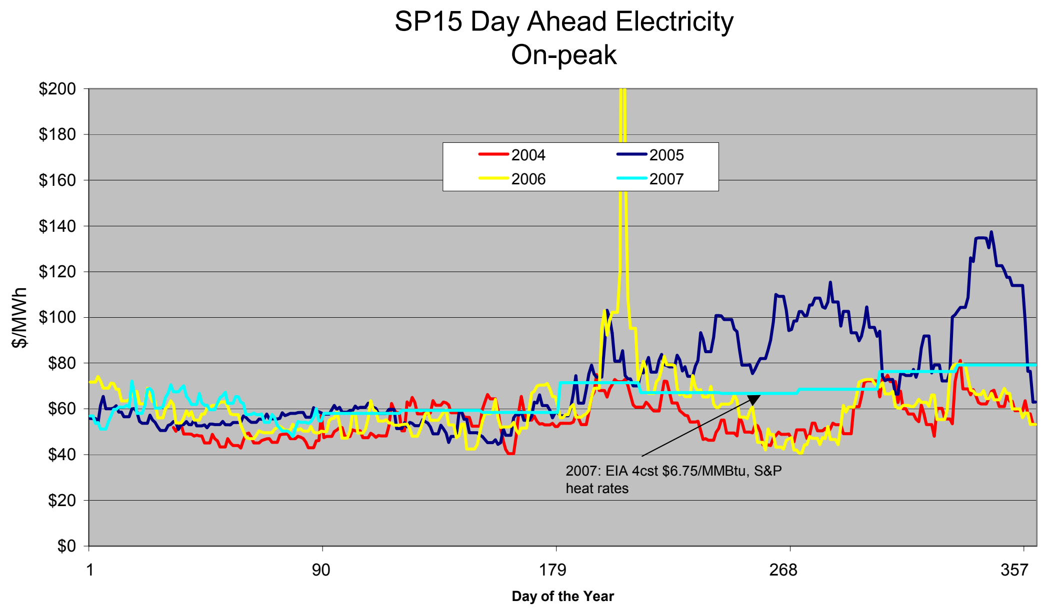

Figure 3: Day Ahead On-Peak Electricity Price, $/MWh, "SP15": Southern California

Figure 3 shows the day-ahead price for on-peak electricity generated in or delivered to Southern California beginning March 2004 through March 2007. During October through March, there is a high correlation between on-peak energy prices and natural gas prices. The correlation is not as strong during off-peak hours. Baseload coal and nuclear generation operate to meet load around the clock, and natural gas units are dispatched during peak hours.

In the middle of the year beginning about June, there is a high correlation between gas and off-peak power prices. The peak period is influenced by capacity concerns: whether there is enough generation to meet demands. Older, inefficient gas-fired generating units and less efficient combustion turbines are dispatched to meet load, and their capacity costs are reflected in peak prices.

In the West, there are select times of the year when gas does not drive prices and a widening of the peak to off-peak price spread occurs. An example is the spring hydro run-off during April and May. During this period, off-peak prices in particular are de-linked from natural gas.

Figure 4 shows the day-ahead price for off-peak electricity generated in or delivered to Southern California. What is interesting is that the off-peak prices over the last two-and-one-half years show even more volatility than on-peak prices. Part of this may be due to the fact that Sundays and holidays are considered off-peak during all 24 hours and the pricing for what would otherwise be on-peak hours are included into the period average price.

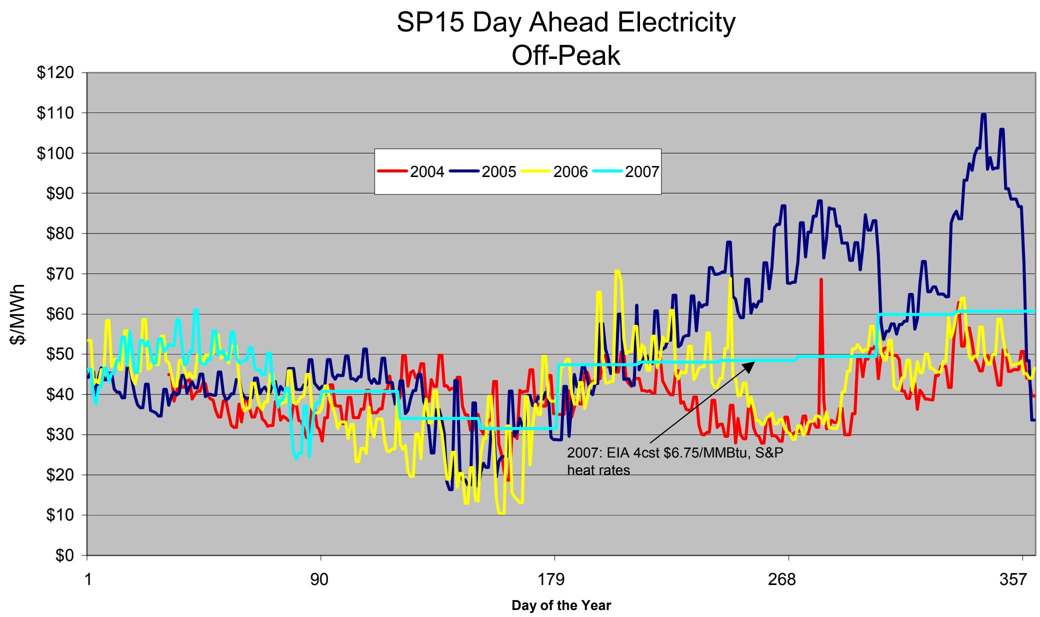

Figure 4: Day Ahead Off-Peak Electricity Price, $/MWh, "SP15": Southern California

The price volatility shown in the natural gas and electricity graphs above is reflected in Metropolitan's own cost structure. In Figure 5, the cost per acre-foot Metropolitan has incurred to pump water on the CRA and the SWP is shown. Both the CRA and the SWP are supplemental energy purchasers, primarily in the off-peak period, although at much different volumes.

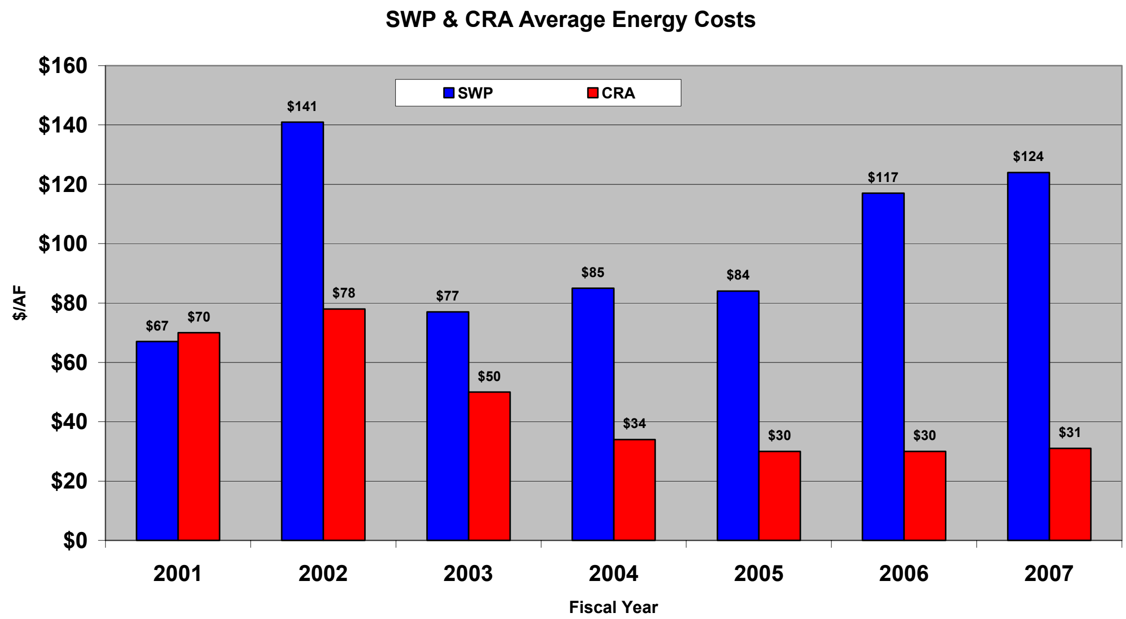

Figure 5: Metropolitan's SWP and CRA Average Energy Costs, $/acre-foot

Costs are relatively low on the CRA because Metropolitan has secured low-cost, hydroelectric and operational contracts through 2017 that can move approximately 780,000 to 800,000 acre-feet annually. Beyond that amount, Metropolitan relies on the market for supplemental purchases. The SWP also uses low-cost hydroelectric and recovery resource, but these only meet about 50 percent of the SWP energy needs. It relies on the market for as much as 30 to 35 percent of its supplemental purchases.

In a fairly short period of time, the energy markets have undergone profound changes and are now far more vulnerable to severe price spikes compared to just a couple of years ago. Energy price volatility can greatly impact transactions even for a short period of time if a purchaser has to come into the market when prices have suddenly spiked upwards, such as the fourth quarter of 2005. Over the last nine years, the trend for wholesale energy prices has been upward. This upward price trend combined with high levels of market price volatility and the influence of gas-fired generation on wholesale energy prices has affected the cost of power on the CRA and the SWP.

Colorado River Aqueduct Energy

Overview

Pumping an acre-foot of water to Southern California from the Colorado River through the Colorado River Aqueduct (CRA) requires about 2.0 megawatt-hours (MWh) of energy. To supply electricity, Metropolitan relies on long-term contracts and ownership rights for generation and transmission, which have a stable cost structure but provide energy that can vary significantly month-to-month and year-to-year.

Metropolitan's primary energy resources are hydroelectric, and are affected by hydrological and environmental events. These long-term contracts historically supplied about 70 percent of the energy requirements for a full CRA of about 1.2 million acre-feet. Through a cooperative scheduling agreement with Southern California Edison Company (SCE), energy from Metropolitan's contractual resources is scheduled to meet mostly on-peak loads, minimizing Metropolitan's exposure to on-peak market prices.

Historically, the remaining 30 percent of the CRA energy requirements for off-peak energy requirements were purchased in the wholesale power market when needed. Figure 6 shows the historical makeup of Metropolitan's energy resources to pump on the CRA.

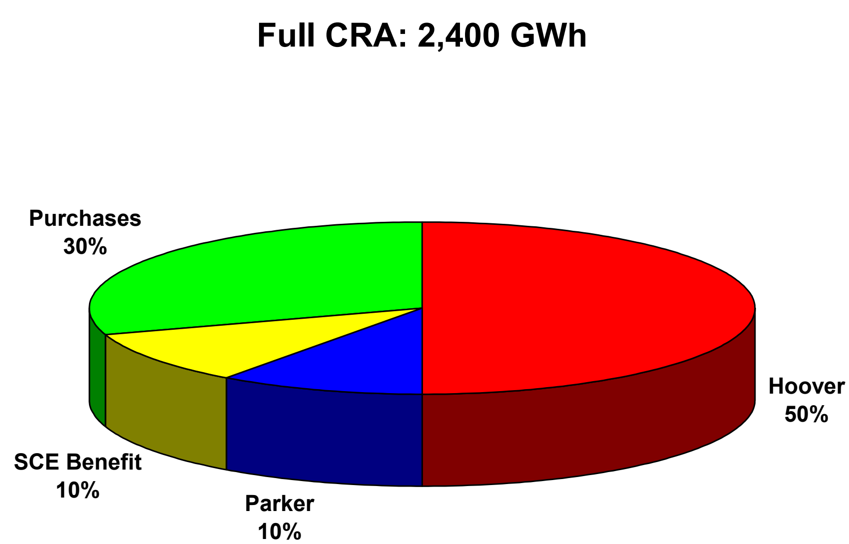

Figure 6: Historical Energy Resources, Full CRA

Due to the significant long-term drought in the Colorado River watershed and negotiations regarding the allocation of Colorado River supplies among the California contractors and the other basin states, California's allocation of Colorado River water was limited to 4.4 million acre-feet annually beginning in 2003. This limitation fell to Metropolitan as the fourth priority use on the river. In 2003, Metropolitan's diversions dropped below 1.2 million acre-feet, as shown in Figure 7.

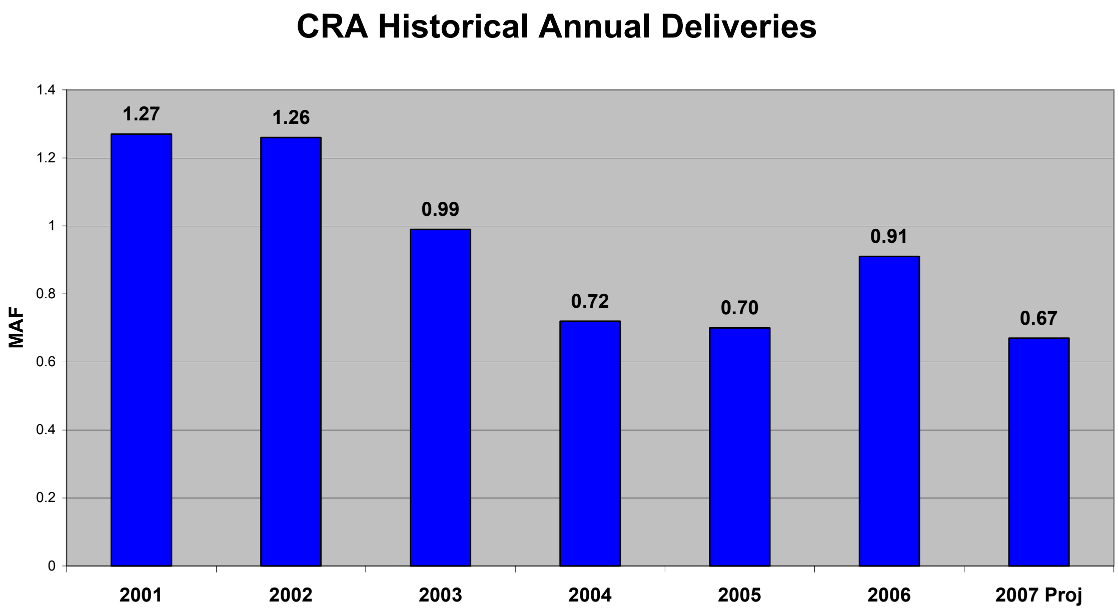

Figure 7: CRA Historical Annual Diversions

In October 2003, Metropolitan and the other California contractors, with the exception of the Palo Verde Irrigation District, executed the Quantification Settlement Agreement (QSA). The QSA lays out a framework for transferring water from agricultural users to urban needs. The QSA identifies specific projects that will result in an increase in diversions through Metropolitan's CRA from the 0.68 million acre-feet realized in 2003. It also allows Metropolitan to access special surplus supplies if hydrological conditions on the river improve. Finally, Metropolitan will facilitate the transfer of water from the Imperial Irrigation District to the San Diego County Water Authority through an exchange agreement.

Recent negotiations between the Colorado River Basin states and the Bureau of Reclamation will allow Metropolitan and other California contractors to store up to 1.5 million acre-feet in Lake Mead. After incorporating the Lake Mead storage program, forecasts for Metropolitan's diversions on the CRA average approximately 0.9 million acre-feet annually for the period 2009 through 2020 and 0.92 million acre-feet annually for the period 2021 through 2030.

These revised operations on the CRA have changed Metropolitan's resource mix in both the long- and short-term. Figure 8 shows the resource mix needed to move varying amounts of water on the CRA. Metropolitan's long-term contracts are expected to supply most of the energy requirements for the CRA through 2017. The remaining CRA energy requirements through 2017 will be purchased in the wholesale power market when needed.

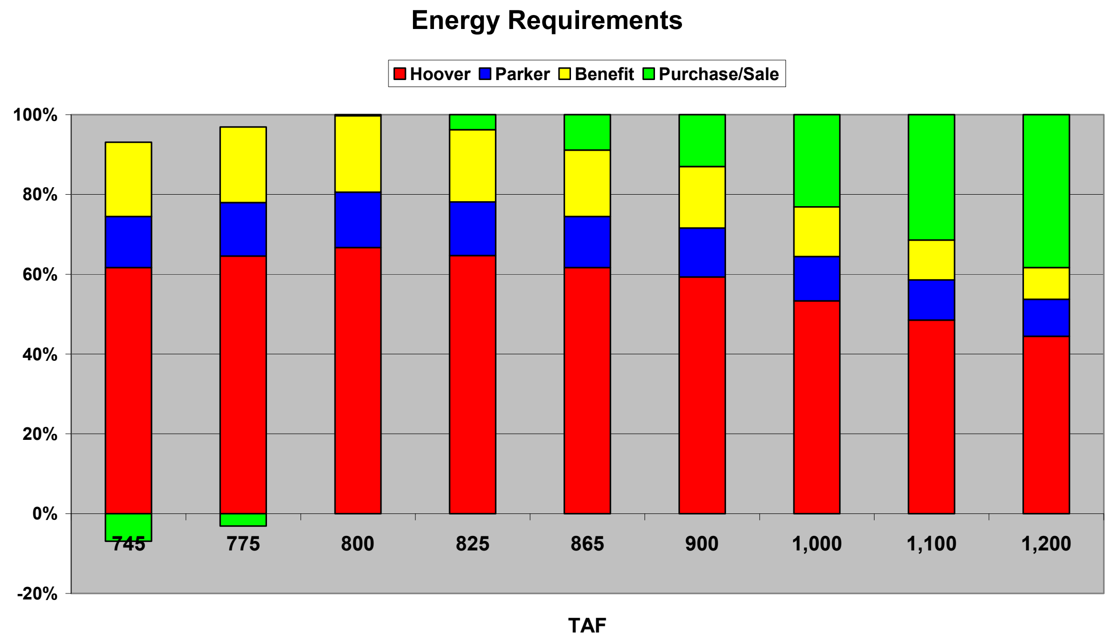

Figure 8: Future Energy Resources, CRA Revised Operations

Current Metropolitan Resources for CRA

Metropolitan has five basic sources of power available to meet energy requirements on the CRA: Hoover Power, Parker Power, Benefit Energy from SCE, Exchange Power with SCE and the California Department of Water Resources (DWR), and wholesale purchases from entities in the Western US.

Metropolitan has a Service and Interchange Agreement (Agreement) with SCE that provides services and benefits to both parties. The Agreement expires in 2017. Under the Agreement, SCE can dispatch Metropolitan's Hoover Dam and Parker Dam power entitlements and utilize excess transmission capacity on Metropolitan's CRA transmission system. SCE in return must meet Metropolitan's CRA energy and reliability requirements on a continuous basis. SCE must also provide Benefit Energy, the amount of which is determined annually, at no cost to Metropolitan for the benefits SCE receives. The contribution of each of those resources from 2002 through 2007 is shown in Figure 9.

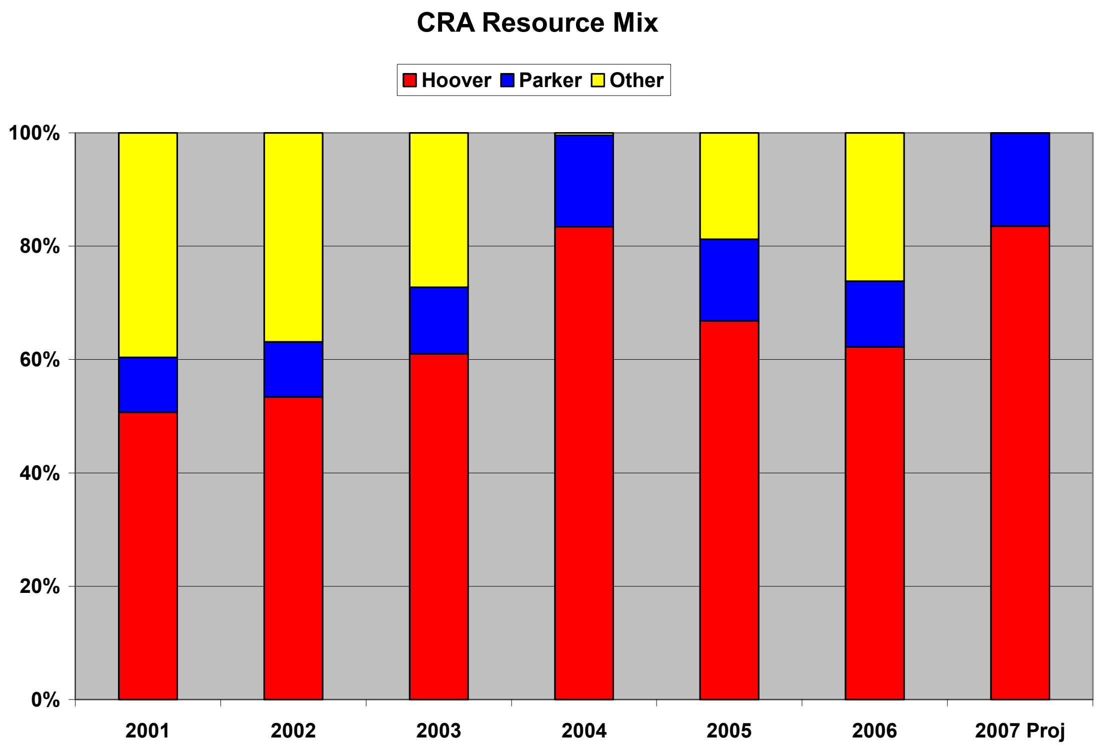

Figure 9: CRA resources

Under a contract between the United States, Department of Energy, Western Area Power Administration, Boulder Canyon Project and Metropolitan, Metropolitan has a right to approximately 247 MW of capacity at the Hoover Power Plant, which is about 12 percent of the total generating capacity. Metropolitan has an annual firm energy entitlement of 1,291 MWh (904 MWh in summer and 387 MWh in winter), which is about 28 percent of the total Boulder Canyon Project (Hoover) firm energy allocations. This contract expires in 2017, concurrent with the SCE Agreement. Hoover Power Plant generation is cost-based. Because of the benefits a low-cost, federally funded hydroelectric plant provides, Metropolitan is prohibited from selling Hoover Power for a profit. Under the Agreement with SCE, SCE can dispatch Hoover Power as they desire, so Metropolitan deems Hoover energy to have been delivered in the on-peak period.

Under a contract among the United States, Department of the Interior, Bureau of Reclamation and Metropolitan, Metropolitan funded the total cost of construction of Parker Dam and incidental facilities, and 50 percent of the construction cost of the Parker Power Plant. By providing the funding contribution, Metropolitan is entitled in perpetuity to 50 percent of the capacity and energy of the four Parker generating units, which is approximately 54 MW of capacity. Parker Power is also cost-based, but there is no limitation on resale of the energy. Parker Power is scheduled hourly. Metropolitan schedules the maximum available in the on-peak period and decreases the schedule to the minimum during the off-peak period.

In consideration of the benefits SCE receives under the Scheduling and Interchange Agreement, SCE provides energy to Metropolitan called Benefit Energy. There is no charge for this energy. The amount of Benefit Energy available annually depends on the usage of the CRA by Metropolitan. Because SCE is obligated to meet the energy and reliability requirements of the CRA, they benefit if the CRA is not operating at full capacity. The relationship between the amount of Benefit Energy provided and pumping load is inverse: the more Metropolitan pumps, the less Benefit Energy SCE provides. Therefore, under the high diversion scenario, Metropolitan receives slightly less Benefit Energy to meet pumping loads than would be realized under a lower diversion scenario. The minimum amount of Benefit Energy provided annually by SCE is 200,000 MWh. The contract sets maximum and minimum amounts of Benefit Energy that can be allocated monthly. Benefit Energy can only be used to meet off-peak energy requirements.

After implementation of the QSA, Metropolitan's resources and loads are not always aligned throughout the year. Metropolitan has agreements with both SCE and DWR to provide, at Metropolitan's option, the exchange of power, which are used to help align power availability with needs. Each agreement covers a 12-month period, with no provision to carryover balances from one contract year to the next. The SCE agreement provides for the exchange year to run from October through the following September, which matches the federal government's fiscal year. The DWR agreement runs from January through December. The power is valued when delivered and returned. SCE and DWR must receive at least the same monetary value from the energy returned as provided, or Metropolitan must pay the difference. If Metropolitan returns energy with a greater monetary value than that provided, there is no payment to Metropolitan.

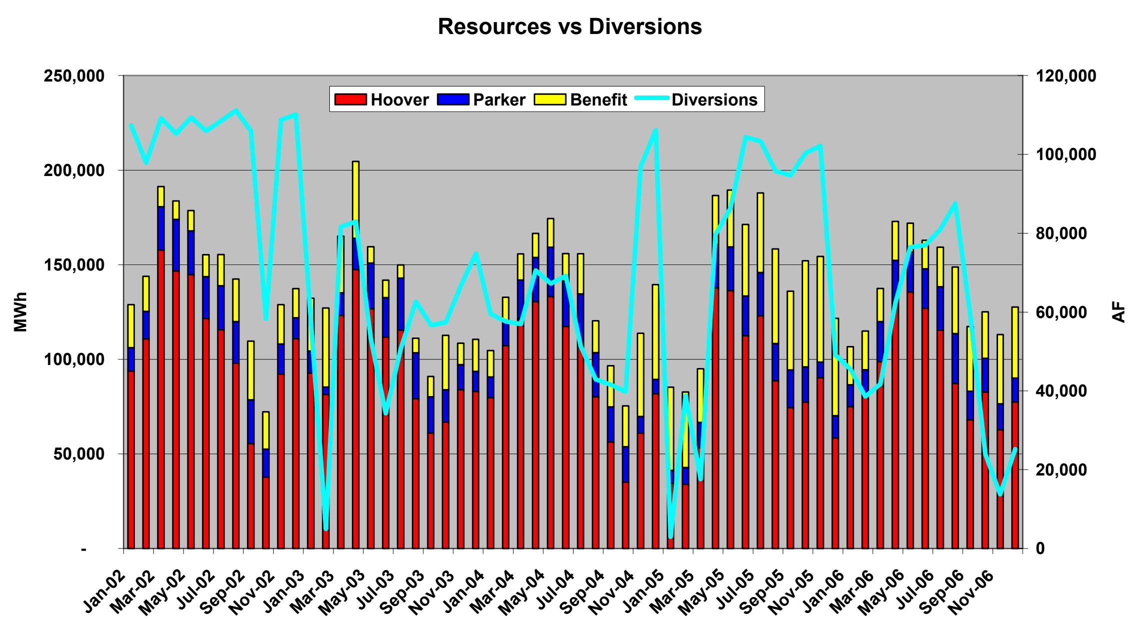

Figure 10: Historical Resources versus Diversions, CRA

Finally, Metropolitan can purchase power to meet any supplemental power needs from entities through the western United States and Canada. Metropolitan executes these purchases either through bilateral contracts or the Western Systems Power Pool (WSPP) agreement. Generally, these purchases are off-peak, and can be transacted in the real-time, day-ahead, or forward markets.

Cost of CRA Resources

The cost of Metropolitan's CRA resource mix is very low compared to the Southern California wholesale market. Figure 11 shows the relative cost of Hoover, Parker and purchased energy on an acre-foot basis since Fiscal Year 2001. Hoover costs have been increasing due to on-going rehabilitation of facilities and post 9/11 security costs. Parker costs have increased also due to rehabilitation of the facilities. The cost per megawatt-hour in Fiscal Year 2007 for Hoover is about \$14/MWh; the cost for Parker about \$16.75/MWh. Benefit Energy from SCE has no price. The melded average cost for the CRA is about \$15.50/MWh, or \$31/acre-foot. For comparative purposes, the cost for round-the-clock energy purchased wholesale in Southern California in 2006 was about \$53.50/MWh.

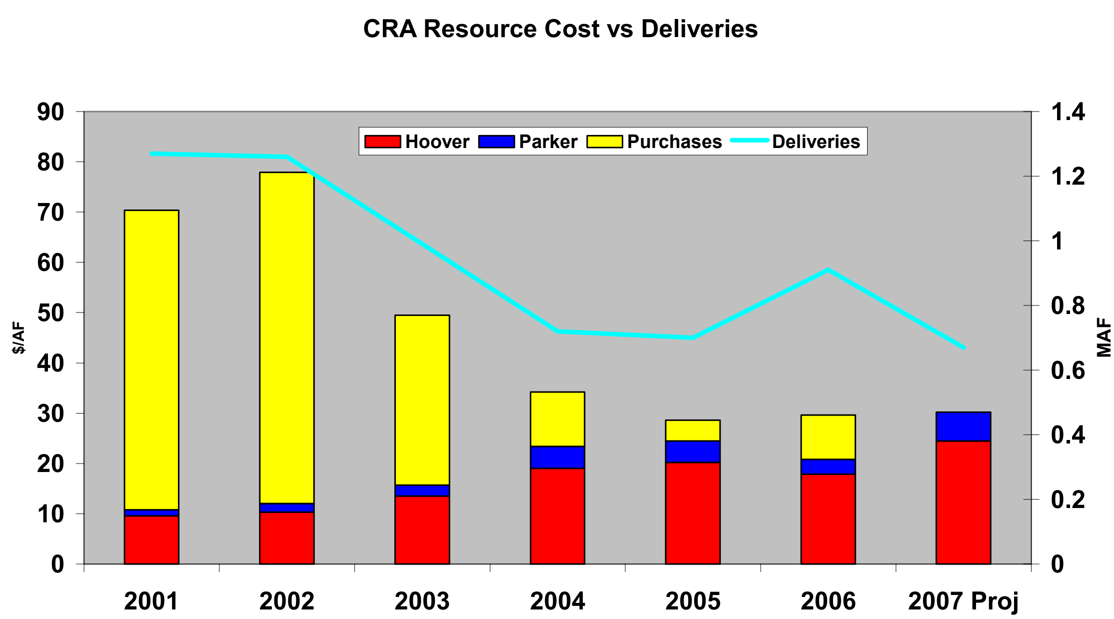

Figure 11: Average Cost of CRA Resources versus Deliveries

Metropolitan's basic resource mix, which can meet delivery requirements for approximately 780,000 to 800,000 acre-feet, is very cost effective. Once those resources are exhausted, Metropolitan must turn to the wholesale market and pay much higher incremental costs. The following Figure 12 shows how purchasing wholesale power to meet incremental energy requirements affects the average cost of power on the CRA utilizing various delivery volumes and incorporating market price risk.

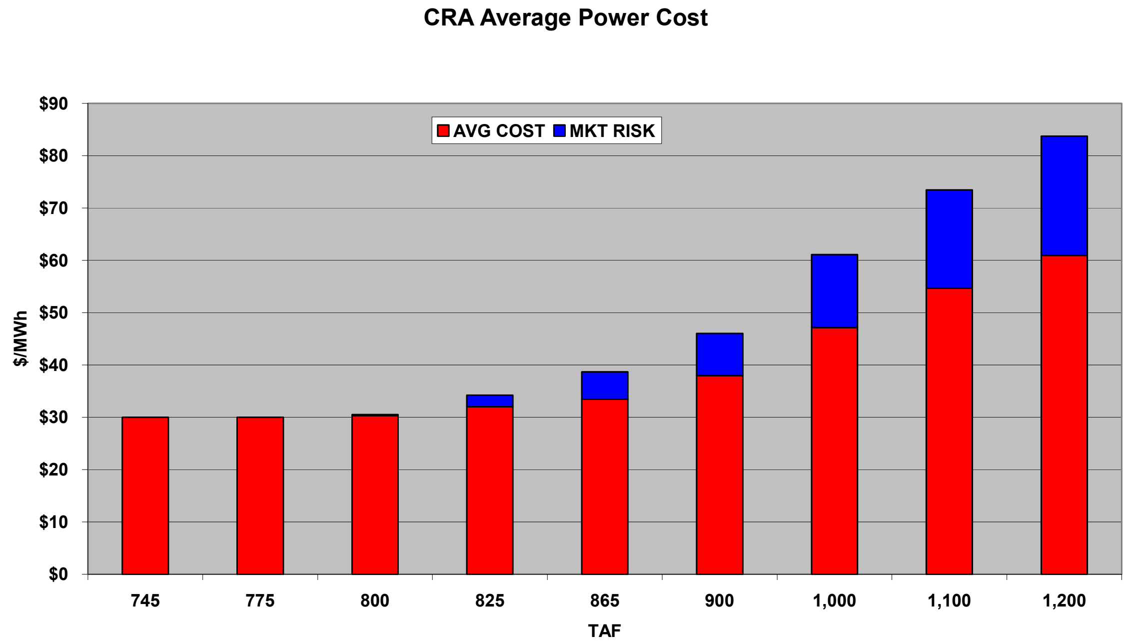

Figure 12: Average Cost of Power at Various Diversion Levels with Market Price Risk

Currently, Metropolitan sells excess energy into the wholesale market and realizes revenues, which offset the total cost of energy as reflected in the System Power Rate. If Metropolitan were to deliver additional water through the CRA, these sales would become a lost opportunity. Metropolitan operates its pumps at a constant load, so the round-the-clock average price of power in Southern California would reflect the energy cost to move the water. While the pumps physically require about 2 MWh to move an acre-foot of water through the CRA, there is an additional financial impact. As explained previously, the amount of Benefit Energy Metropolitan receives from SCE is inversely proportional to Metropolitan's use of the CRA. The less water Metropolitan pumps, the more Benefit Energy received from SCE. The impact of moving an additional acre-foot of water reduces the amount of Benefit Energy received from SCE and is estimated at .317 MWh. So, the financial impact of moving an additional acre-foot of water is 2.317 MWh. In 2006, the average market price for power in Southern California was $56.60 per MWh for round-the-clock energy. Multiplying $56.60 per MWh and 2.317 MWh yields an incremental cost to pump on the CRA of about $124 per acre-foot in 2006.

In the long term, key contracts will expire in 2017, including Hoover and the SCE Service and Interchange Agreement. Metropolitan's resource mix and costs will likely change, and Metropolitan may face increased exposure to both on- and off-peak wholesale energy prices. Metropolitan will likely also have to address issues of renewable generation and greenhouse gas emissions reduction.

State Water Project Energy

Overview

The State Water Project (SWP) was constructed to provide about 4.2 million acre-feet to contractors on an annual basis. Typically, deliveries are less than this amount so excess pumping capacity is available. As a result of reduced delivery requirements and design features at certain hydroelectric plants, the SWP generally has the operational flexibility to maximize pumping during the off-peak period and minimize pumping in the peak period. The desire to minimize pumping during peak hours can conflict with other operational objectives, such as the timing of water requests, environmental considerations, and flood control requirements.

The cost of energy for the SWP is dominated by three factors: 1) the variability of energy requirements in any year; 2) hydrologic risk; and, 3) market price risk.

The variability of energy requirements is due to many factors. There are 29 SWP contractors whose demands vary with the water year and water availability as the SWP is a supplemental supplier. In an above-normal rainfall year, SWP demands generally will be lower than during a dry year as local resources are first used to meet demands. Other factors affecting the amount of energy required by the SWP to meet deliveries are the timing of requests for deliveries, where the water is located (north or south of the Delta), pump unit availability to optimize on-peak generation and off-peak pumping, environmental considerations, flood control requirements, and system optimization goals (storage and other operating targets). The effect of energy requirement volatility is presented by the red markers in Figure 13.

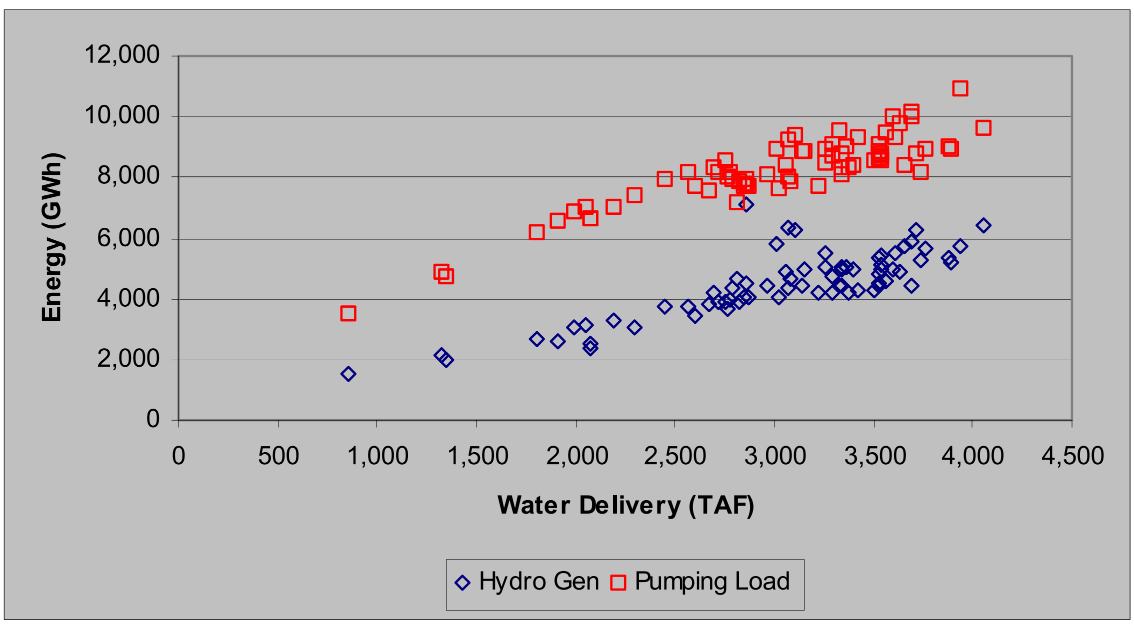

Figure 13: Variation of SWP Hydro generation and Pumping Load with Annual Water Delivery Amount Requirements

As this figure shows, even over a likely range of deliveries of 2,500 TAF to 3,500 TAF, energy requirements to meet pumping load can be as low as 7,000 GWh and as high as 10,000 GWh, a 50 percent variance.

Contractor deliveries are not the only significant variable. The SWP is exposed to variability in its resource portfolio to meet pumping loads from one year to the next. A significant portion of the generation used to meet SWP resource needs is hydroelectricity generated at Hyatt-Thermalito near Oroville. This resource is affected by the hydrology of the Feather River system that feeds into Lake Oroville, so the amount of generation that is available from Hyatt-Thermalito can vary significantly year to year. The SWP also has five recovery generation facilities located along the California Aqueduct that generate power as water is conveyed through the SWP system. The amount of generation produced by the recovery generators depends on the amount of water DWR is moving.

Figure 13 shows the variability of hydroelectric generation over the range of deliveries, as depicted by the blue markers. Over a likely range of deliveries of 2,500 TAF to 3,500 TAF, the amount of generation realized can be as low as 3,500 GWh and as high as 7,000 GWh, a 100 percent variance.

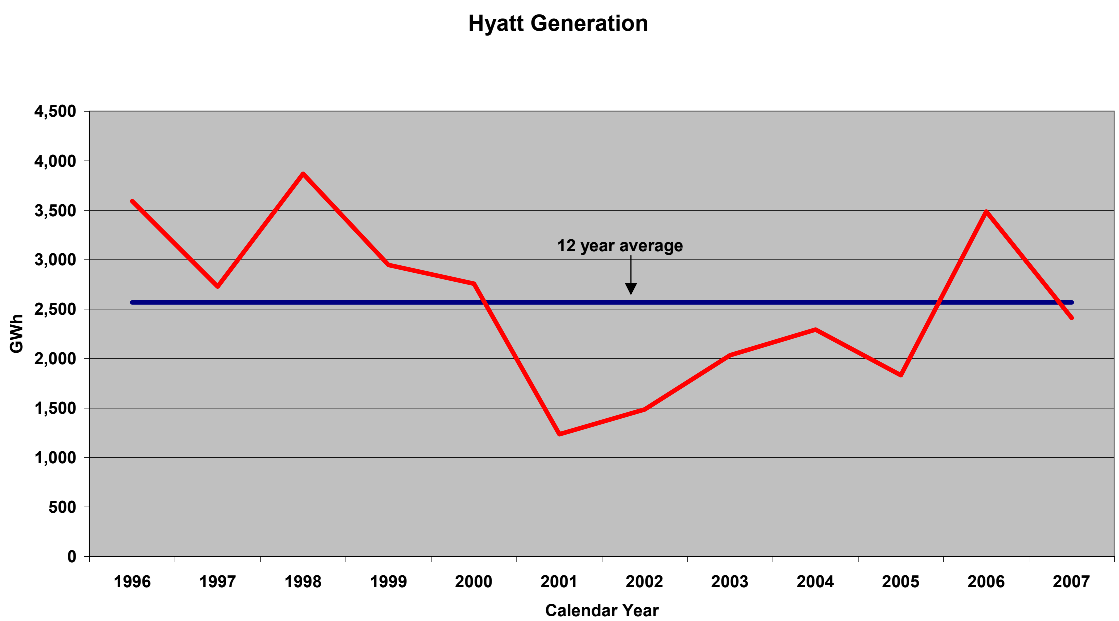

Figure 14: Generation from Hyatt-Thermalito Power Plant

This is a direct reflection of the operations of Hyatt-Thermalito. Figure 14 shows the variation in the amount of annual generation realized at Hyatt-Thermalito since 1996 compared to an average over the same period. Comparing several years is very instructive. Calendar year 2005 was actually a dry year on the Feather River basin. Releases from Hyatt-Thermalito were below normal, as was the resulting generation. The Federal system, however, had a wet year and the SWP was able to make deliveries based on releases from Shasta reservoir. Calendar year 2006 was a record wet year. Flood control releases beginning in January resulted in higher power generation; the releases were not made to meet contractor demands. In 2007, rainfall on the Feather River basin is again below normal and generation from Hyatt-Thermalito is expected to be below the twelve-year average.

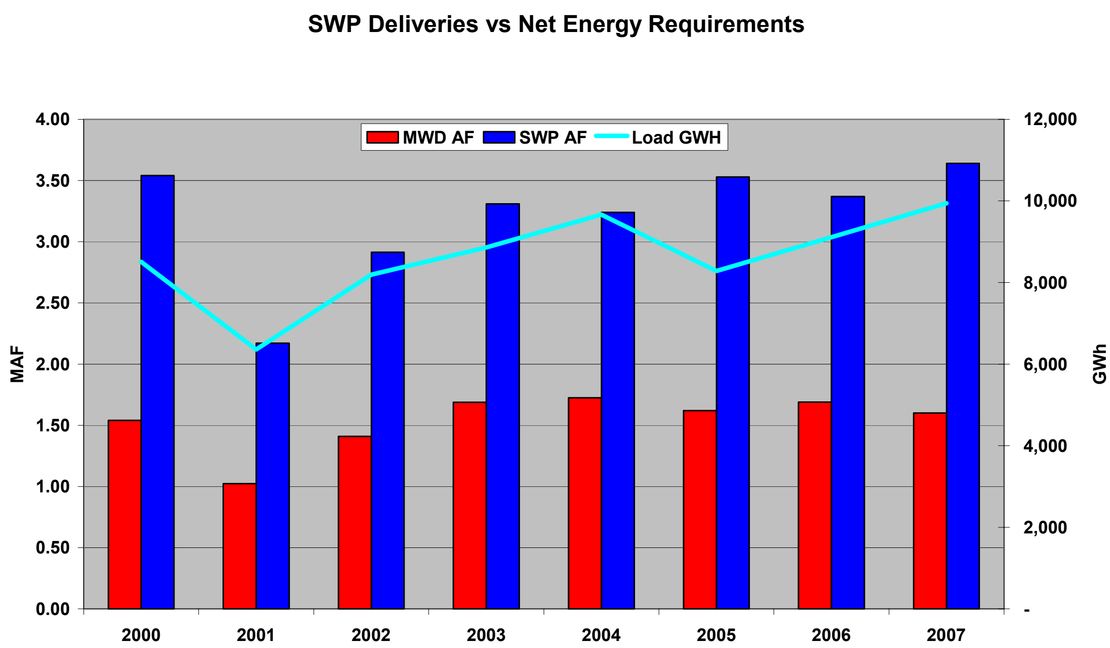

Figure 15: Historical Calendar Year SWP Deliveries to Contractors and Net Energy Requirements

Historically, Metropolitan delivered 1.2 MAF of CRA supplies, and used the SWP as a supplemental source for additional deliveries above those available on the CRA. Since implementation of the Quantification Settlement Agreement, which limited California's use of the surplus Colorado River water, Metropolitan has had to reduce its Colorado River water imports and increase the use of SWP water.

Metropolitan moves the largest amount of water on the SWP. Metropolitan's contracted share is 46 percent of the SWP supply. Metropolitan's delivery points on the East and West Branch are at or near the southern extreme of the SWP and require substantial amounts of energy to pump water through the Central Valley and up over the Tehachapi mountains. Because of this, Metropolitan's delivery requests influence the amount of energy the SWP requires, but the relationship is not exact (see Figure 15).

Figure 16 summarizes the SWP challenge. The variability of hydroelectric generation from the SWP combined with the variability of contractor water deliveries creates a very large and unpredictable energy risk position for the SWP.

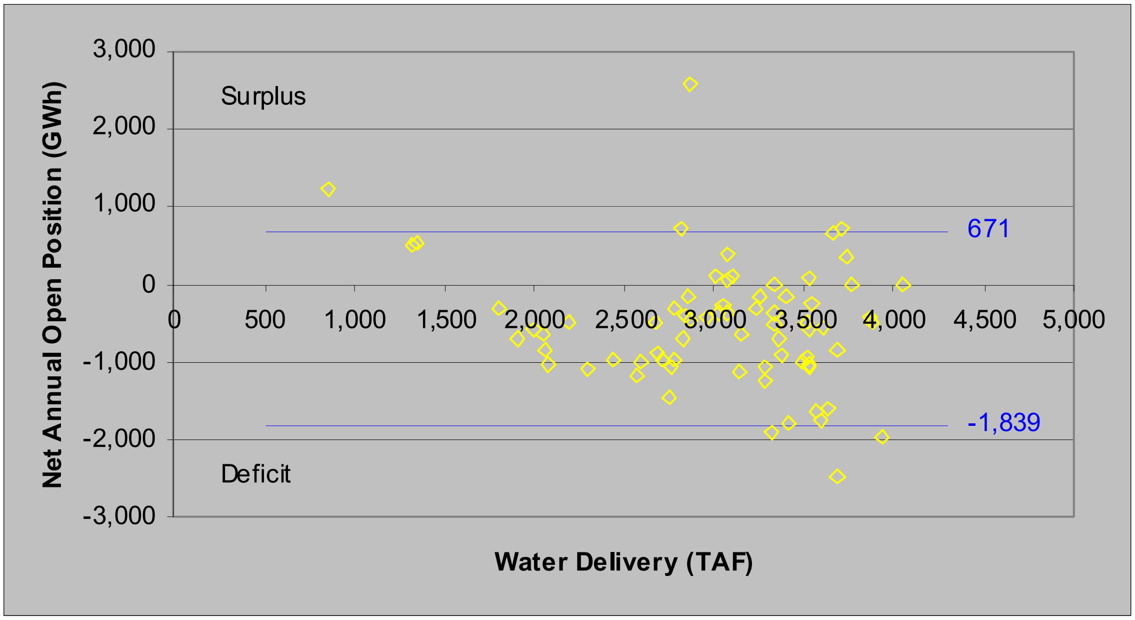

Figure 16: Variation of Net SWP Open Position versus Annual Water Delivery Amounts

The SWP's net energy position can range between 10 percent over-resourced to 20 to 30 percent under-resourced. While other electric utilities experience variability in the output of their hydroelectric generation, the variability of energy requirements on the SWP is unique. Pumping requirements can vary by as much as ±40 percent from one year to the next. There is a lack of predictability from year to year, or even within a calendar year, with regard to contractor demands as the SWP is a supplemental supply. For comparative purposes, a typical retail electric utility may experience a 3 to 5 percent variation in demands due to weather. The extreme variability on the requirements side of the equation makes resource planning and procurement much less certain for the SWP.

This introduces the third factor affecting the cost of energy for the SWP, namely market price risk. Market price risk affects the 20 to 30 percent of requirements that the SWP is short by exposing the SWP to uncertain and potentially higher energy prices. It also affects hedged volumes when they are revalued at current market prices and are found to be higher, resulting in the contractors paying more for power than they otherwise would have.

SWP Operational Characteristics

DWR operates the SWP in a manner that is unique compared to other electric utilities. Retail electric utilities generally have systems that reflect industrial and residential energy use. These uses require more energy during the hours of 7:00 am to 10:00 pm, and diminish during the hours of 11:00 pm to 6:00 am, when factories are idle and people sleep. Retail electric utilities attempt to shape their resource portfolio to meet these energy requirements.

Because of the operational flexibility that exists in the SWP, the DWR does not operate in this manner. Figure 17 shows a typical daily operational pattern for the SWP.

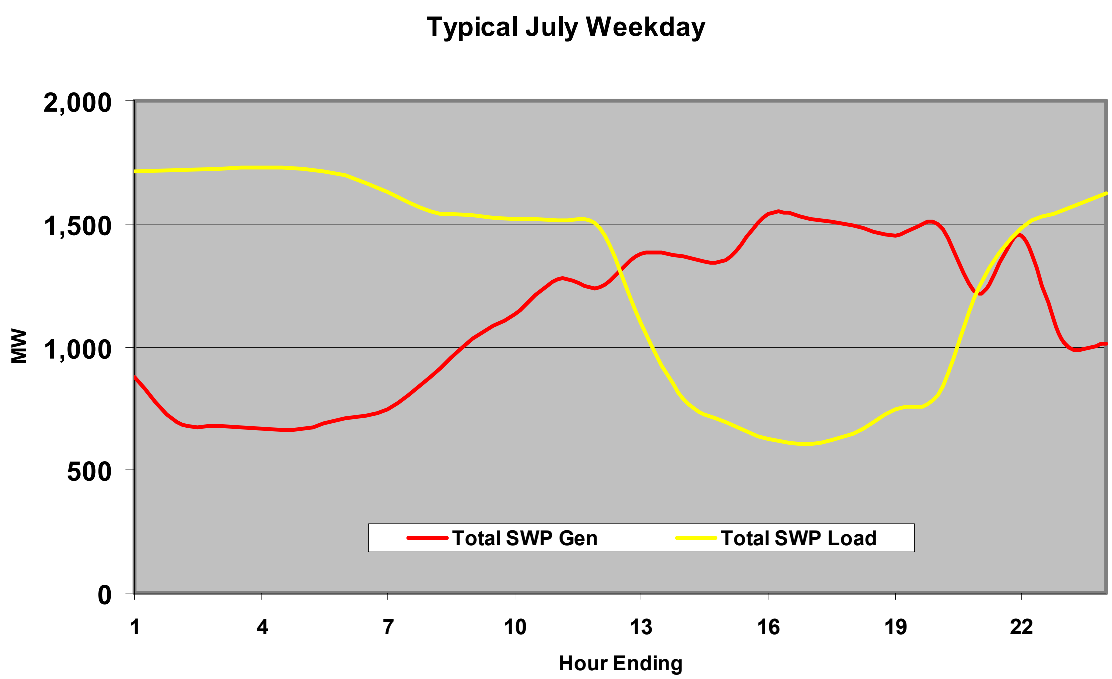

Figure 17: SWP, Typical Daily Operations

There is no matching of loads and resources. The SWP attempts to maximize off-peak pumping, as shown in the yellow line in Figure 17, when energy costs are generally lower. The red line shows how DWR dispatches its resources. DWR operates Hyatt-Thermalito, Devil Canyon and Reid Gardner not necessarily to meet loads but as a revenue source. The output is either sold into the energy market or bid into the California Independent System Operator's Ancillary Services markets during peak hours. The revenue from selling into the energy and Ancillary Services markets is used to purchase power during off-peak hours, when power is usually cheaper.

Figures 18 and 19 show the DWR's short-term purchases and sales during on- and off-peak periods for calendar year 2004 and 2005. From the two figures, it is apparent that while DWR actively purchases and sells during the on-peak and off-peak hours to balance loads and resources, sales volumes, even in 2005, are much lower than short-term purchase volumes. Also, while the SWP attempts to minimize on-peak pumping, it nevertheless is purchasing on-peak energy to meet pumping requirements, particularly during the summer when demands from agricultural users and urban users peak.

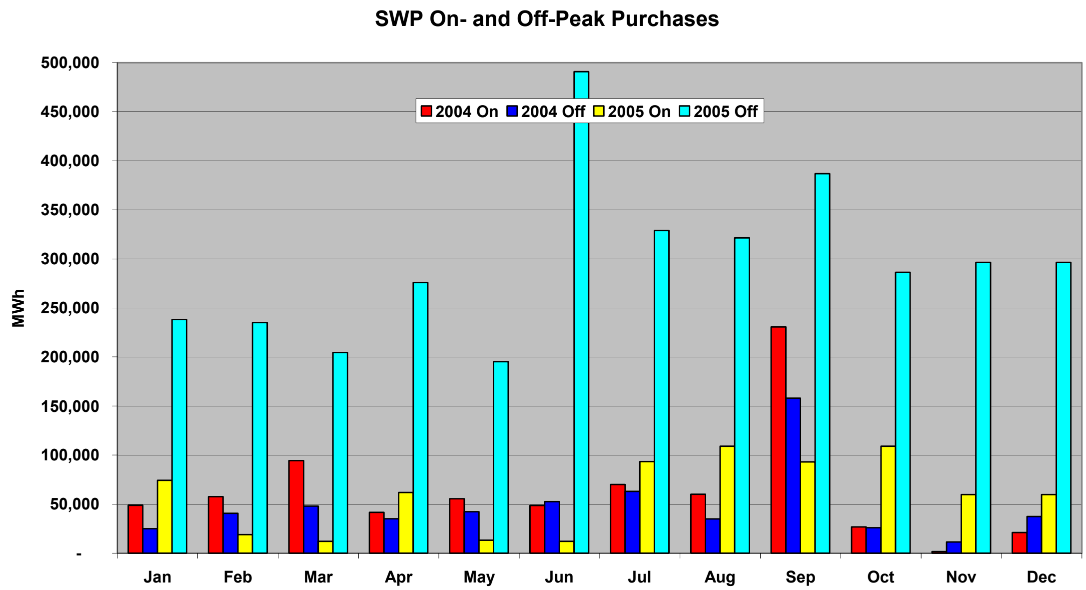

Figure 18: SWP Energy Transactions, Monthly Purchase Volumes

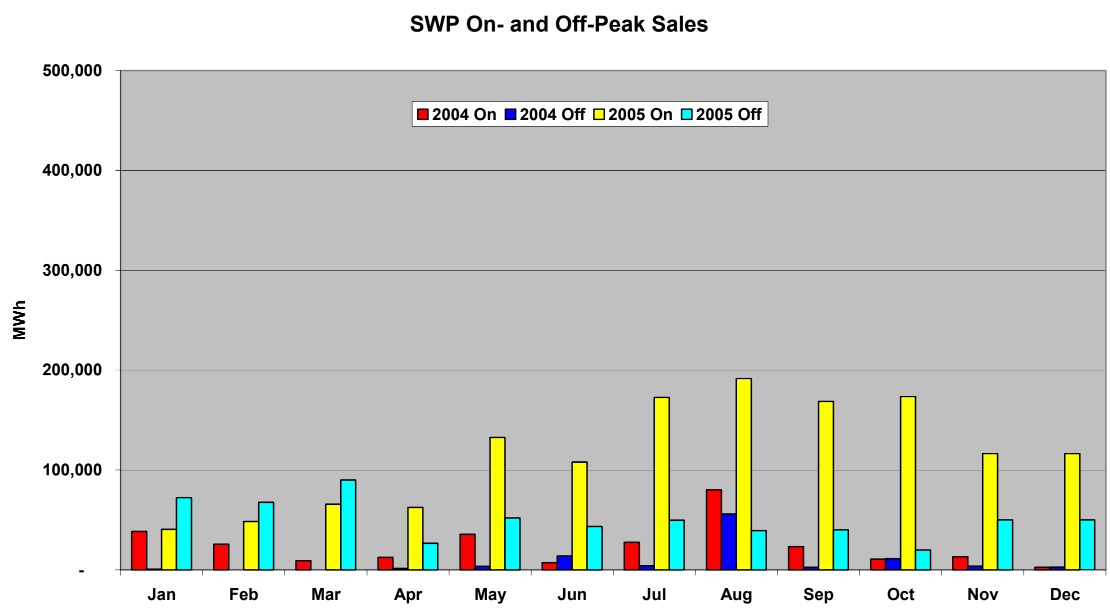

Figure 19: SWP Energy Transactions, Monthly Sales Volumes

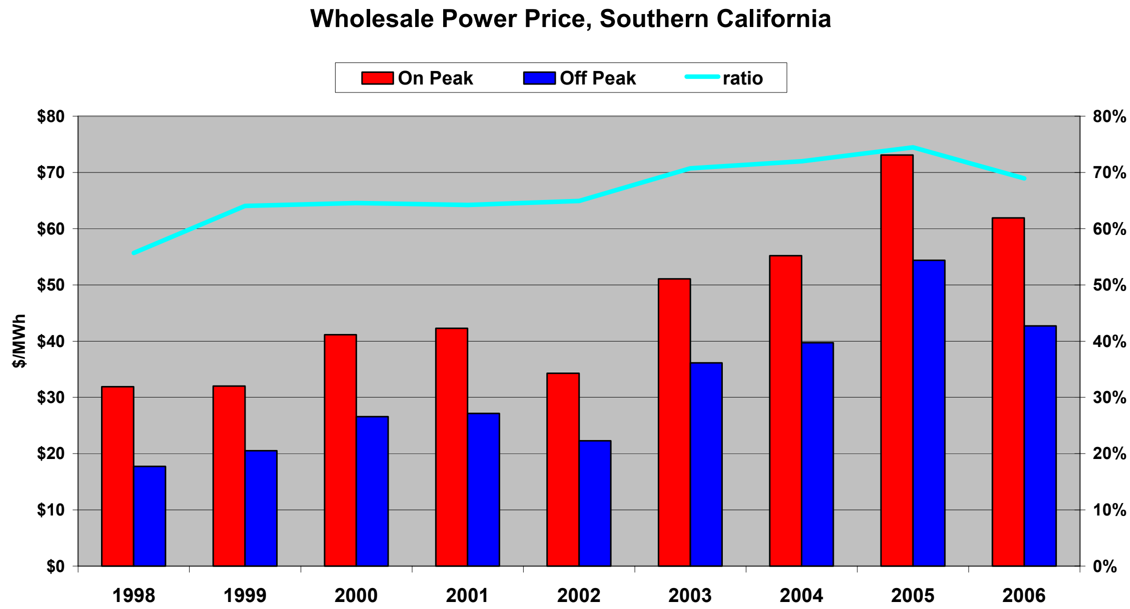

Figure 20: Wholesale Power Prices, Southern California, 1998 through 2006

Figure 20 shows historical wholesale power prices in Southern California, with the ratio of off-peak to peak prices. The ratio is an important indicator to DWR due to their strategy of selling off-peak and buying on-peak. In order to be able to buy 2 MWhs off-peak for every 1 MWh sold on-peak, the ratio between the two prices needs to be in the range of 60 percent.

In 1998 and 1999, the differential between on- and off-peak power prices was substantial enough that the Department of Water Resources could buy on average approximately 1.7 MWh of energy off-peak for every MWh sold on-peak. In 2006, that ratio dropped to 1.4 MWh of energy off-peak for every MWh sold on-peak. This erosion of the price differential is due to the several reasons. The cheap off-peak power came from nuclear and coal plants, which utilities could not entirely back down during low load hours so the excess was sold at incremental (i.e., fuel) cost. Some of that generation has been retired[4]; native load growth by the owning utilities requires the balance. Incremental off-peak load requirements are now met by natural-gas fired generation.

This means that it now takes more money to purchase off-peak power for the SWP relative to the on-peak revenues generated, in addition to the cost escalation that has occurred in the wholesale market. The result is that DWR's strategy of selling generation on-peak to buy off-peak is not as cost beneficial as it once was.

[4] Mohave Generating Station near Laughlin, Nevada, is an example of a coal generating plant that recently ceased operating. It was owned jointly by Southern California Edison Co., Nevada Power Company, the Los Angeles Department of Water and Power, and the Salt River Project.

SWP Energy Resources

Figure 21 shows the percentage of various resources used to meet the SWP energy requirements.

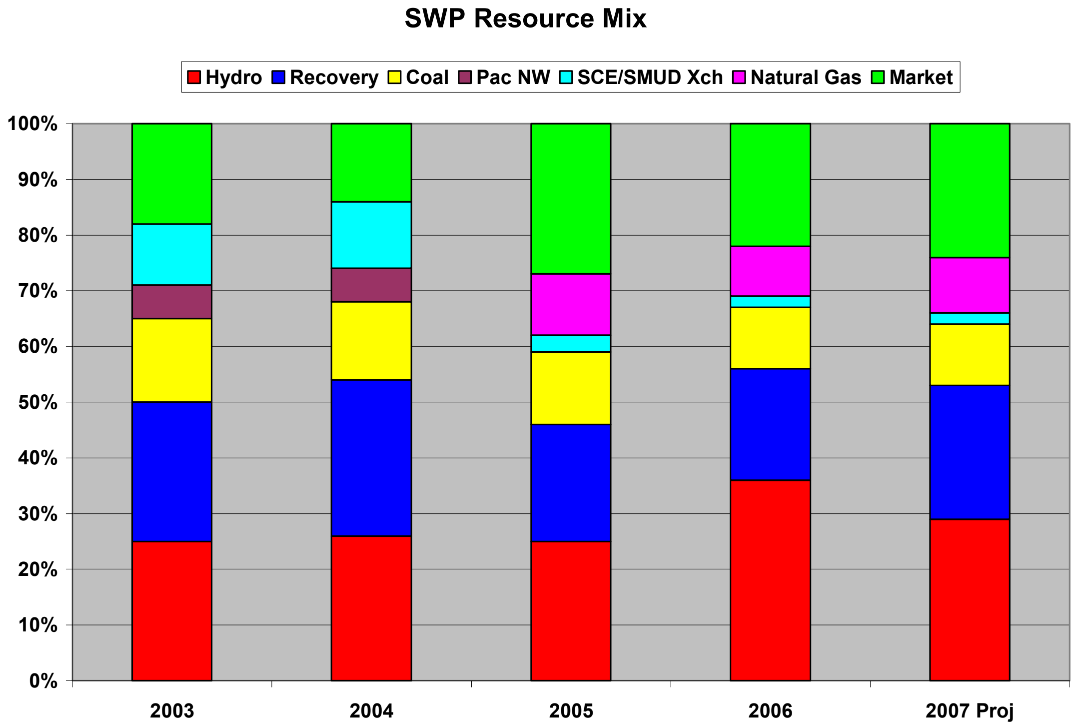

Figure 21: SWP Actual and Projected Energy Sources

The resources the SWP has available in any year can vary widely. A significant portion of the generation used to meet SWP resource needs is hydro-electricity generated at the Hyatt-Thermalito power plant at Lake Oroville. As stated previously, this resource is affected by the hydrology of the Feather River system that feeds into Lake Oroville, so the amount of generation that is available from Hyatt-Thermalito power plant varies year to year. Hyatt-Thermalito costs have varied over the 2003 to 2006 timeframe from about \$11 per MWh in 2006, a very high generation year, to \$23 per MWh in 2003. All units at the Hyatt Power Plant have been replaced, improving efficiencies. During this period, Hyatt incurred additional O&M expenditures for FERC relicensing activities. The original FERC hydropower license for the Oroville Facilities expired January 31, 2007; the Oroville Facilities are operating under an annual license.

The SWP also has five recovery generation facilities located along the California Aqueduct that generate power as water is conveyed through the SWP system—Alamo, Devil Canyon, Gianelli, Mojave Siphon and Warne. The amount of generation produced by the recovery generators depends on the amount of water DWR is moving. The costs over the 2003 to 2006 timeframe have been consistently in the $28 to $29 per MWh range.

Since 1983, DWR has received energy from Reid Gardner Unit 4. The Reid Gardner Power Plant is a coal-fired facility near Moapa, Nevada. DWR owns 67.8 percent of Unit 4, with Nevada Power Company (NPC) owning the remainder of Unit 4 as well as Units 1, 2 and 3. NPC is the operating agent for the plant. Under an agreement between DWR and NPC, DWR receives up to 235 MW from Unit 4, subject to NPC's limited right to recall DWR's energy deliveries during specific periods. Whenever NPC interrupts DWR's scheduled energy, DWR is paid based on NPC's cost of dispatching a gas-fired combustion turbine. Costs have been increasing at Reid Gardner, from $39 per MWh in 2003 to $55 per MWh in 2006. Reid Gardner has been affected by increasing coal costs and significant capital expenditures to mitigate environmental issues. DWR's contract with NPC expires in 2013 and DWR has provided notice to NPC that it will not seek to extend the contract.

Through exchanges and long-term contractual agreements, DWR obtains additional resources. DWR has an exchange with the Sacramento Municipal Utility District to provide energy during the winter in exchange for energy during the summer. DWR also has a long-term contracts for the output of the Pine Flat Power Plant, owned and operated by the Kings River Conservation District, and five of Metropolitan's hydro-electric plants.

Reflected in Figure 21 is the impact of the expiration of two exchange contracts in 2004. A portion of those contracts was replaced by power purchase agreements now with Morgan Stanley, which are based on the price of natural gas settled monthly. The cost of the Morgan Stanley/Duke contracts has averaged about $55 per MWh in 2005 and 2006.

Finally, DWR can purchase power to meet any supplemental power needs from entities through the western United States and Canada. DWR executes these purchases either through bilateral contracts or the Western Systems Power Pool (WSPP) agreement. Generally, these purchases are off-peak, and can be transacted in the real-time, day-ahead, or forward markets. The amount of energy procured from the market, which is now often based on the price of natural gas, has increased since 2004, and can account for as much as 30 to 35 percent of the resources needed for SWP. Overall, DWR's average cost of power for the SWP, including Reid Gardner and two stranded investments in geothermal plants, has increased from $35 per MWh in 2003 to current estimates of $46 per MWh in calendar year 2007.

Cost Recovery of SWP Resources

Figure 22 shows Metropolitan's power costs per acre-foot for the SWP, on a fiscal year cash basis from 2001 through 2007. The State Water Contracts are cost recovery contracts. All SWP service charges are designed to recover the costs incurred by the State in providing services to the SWP contractors on an equitable basis that reflects each contractor's use of the service. The commodity pricing methodology is specified in the water supply contracts. There is no fee or profit element in the charges. DWR reports SWP costs and calculates charges on a calendar year basis using accrual accounting.

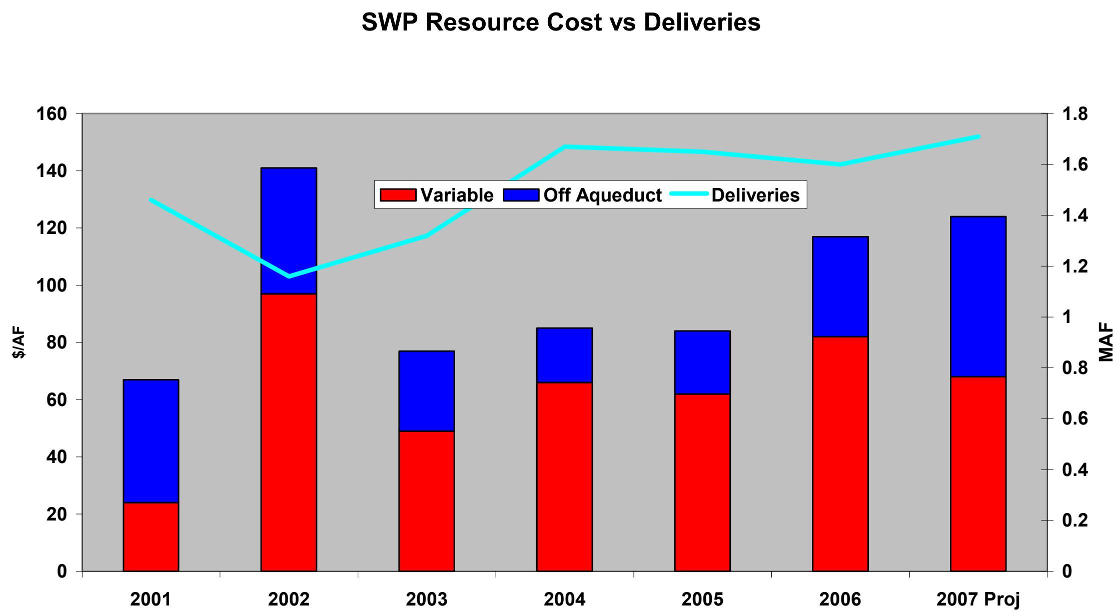

Figure 22: Metropolitan's Fiscal Year Cash Basis Cost of Power, SWP

Two charges make up what Metropolitan defines as SWP power costs. These are the Transportation Variable Operations, Maintenance, Power, and Replacement (Variable) charge and the Off Aqueduct Power Facilities (OAPF) charge. Because the SWP contracts are cost recovery contracts, the Department of Water Resources invoices Metropolitan on an estimated basis for any calendar year, then provides credits in later years once cost true-ups are finished.

A Variable charge component is any SWP cost that varies with the quantity of water delivered. The Variable charge includes the annually estimated cost of purchased power including capacity and energy, cost of SWP power generation facilities, program costs to offset annual fish losses at the Banks Pumping Plant, purchased transmission services, and credits for sales of ancillary services and excess SWP system power sales. The Variable charge is assessed per acre-foot of water at the contractor's point of delivery.

The Variable charge is calculated on the basis of the energy required to pump an acre-foot of water to its take-out point multiplied by the system energy rate, less energy from the recovery generation plants. The system energy rate is a system-wide average rate calculated as the net cost of energy--total costs less revenues--divided by the net energy required to pump all water. DWR can adjust the system energy rate as the calendar year progresses in order to reflect actual costs.

The following Figure 23 demonstrates this process in calendar year 2006. The red bars are the SWP actual variable cost of energy each month, net of revenues. The yellow line is the rate in dollars per MWh DWR used to invoice the contractors for deliveries on a monthly basis. In the past, DWR has used conservative factors to estimate the unhedged energy needs of the project, resulting in a higher invoicing rate early in the calendar year that is lowered as the year progresses and the number of risk factors is reduced. The blue line represents DWR's estimate of the annual average variable invoicing rate it would charge to contractors over the course of the calendar year.

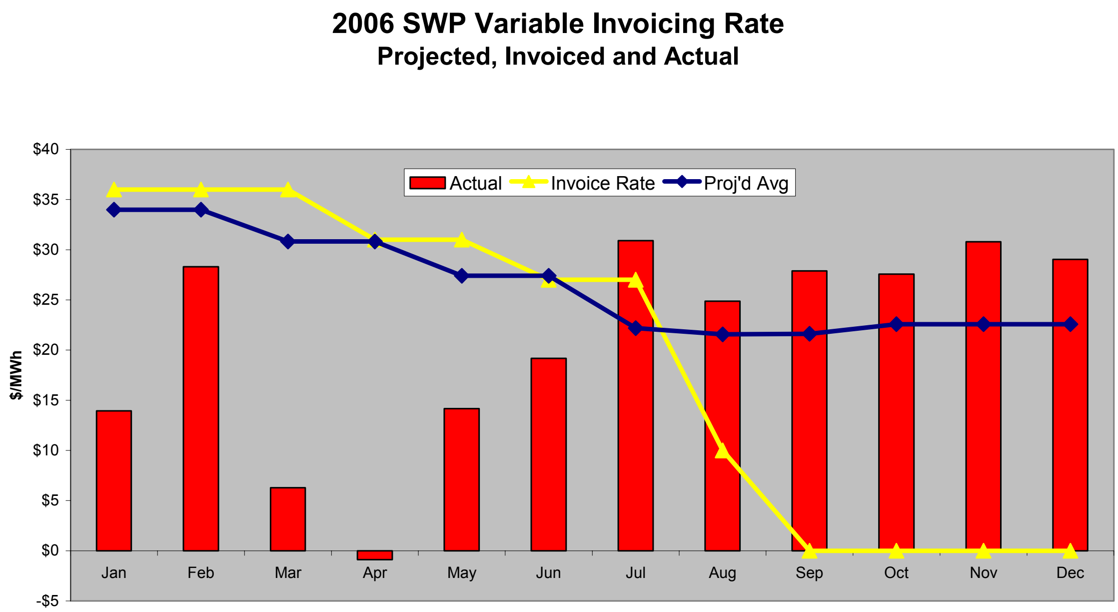

Figure 23: Calendar Year 2006 SWP Variable Invoicing Rate

The Off Aqueduct Power Facilities (OAPF) charge recovers the debt service and estimated annual operations and maintenance costs of power generation facilities not on the aqueduct, namely Reid Gardner Unit 4 and debt service associated with the South Geysers and Bottle Rock geothermal plants. The OAPF rate is calculated as the total annual estimated costs divided by the total energy required to pump all water. Recovery energy is not considered in this calculation. Each contractor's charge is the OAPF rate times the energy required to pump the contractor's water order.

The SWP energy requirements to move water to Metropolitan on the East Branch through Devil Canyon are 3,236 kWh per acre-foot (4549 kWh pumping less 1,313 kWh recovery); on the West Branch through Castaic, the energy requirements are 2,580kWh/AF (4,126 kWh pumping less 1,546 kWh recovery). Because Metropolitan moves the largest amount of water on the SWP (Metropolitan's contracted share of water is 46 percent of the SWP supply) and Metropolitan's delivery points on the East and West Branch are at or near the southern extreme of the SWP, Metropolitan pays between 70 to 75% of the SWP power costs.

In the long term, several of the resources currently meeting SWP requirements will expire over the next 7 to 8 years. As stated previously, the Reid Gardner participation agreement expires in 2013; DWR has indicated it will not seek to extend the contract in response to State policy to reduce greenhouse gas emissions. One-third of the Morgan Stanley natural gas-based contract expires in 2010; the other two-thirds expires in 2015.

In order to address these issues, as well as State policy encouraging the development of renewable generating resources, DWR has taken several steps. DWR reorganized and formed a Power Planning and Risk Management Office to address power planning and contract management, strategic power planning, and risk management. DWR is preparing several studies to better manage forecasting and cost issues that impact energy costs and is in the process of developing a Strategic Energy Resources Plan.

Summary

In summary, it is relatively less expensive to pump an acre-foot of water on the CRA compared to the SWP, but not as much as might be indicated from average cost numbers usually reported for financial purposes. As the analysis above shows, both systems are in the wholesale market on an incremental basis. Because of the different nature of the operations of the two systems, the CRA can purchase off-peak energy to meet some part of the additional energy requirements while the SWP is generally purchasing all additional energy requirements in the peak period. Using the analysis above, the additional cost of delivering to the West Branch is about 20 percent more than the CRA, not the 300 percent that might be inferred from graphs showing average costs.

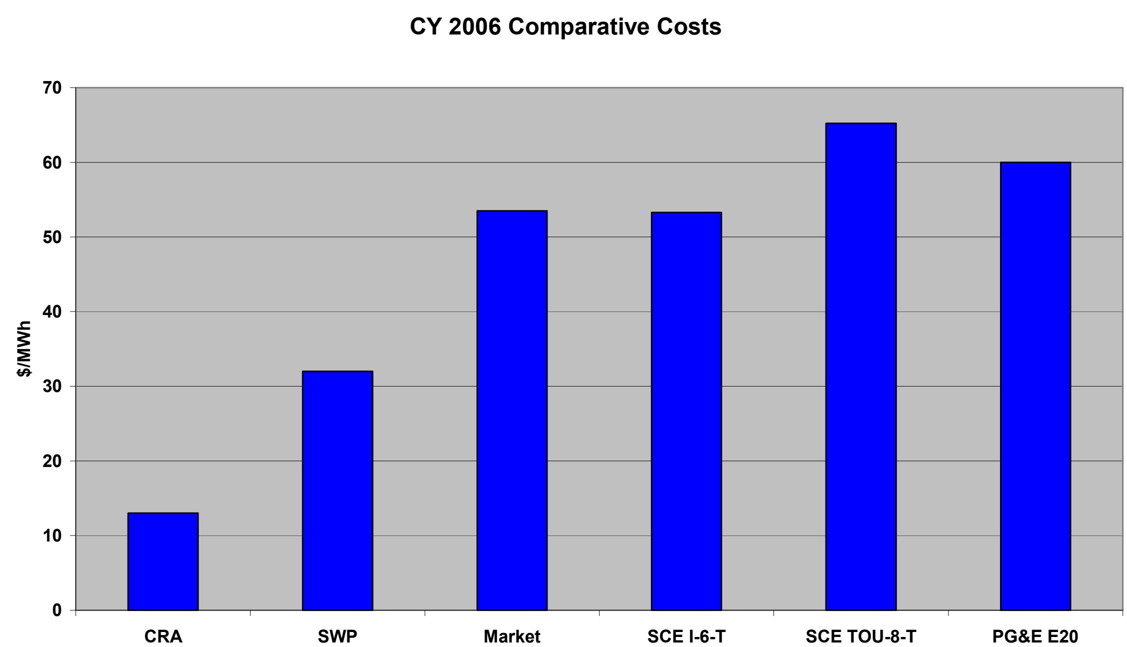

Figure 24: Calendar Year 2006 Comparative Costs, Average $ per MWh

Costs are relatively low on the CRA because Metropolitan has secured low-cost, hydroelectric and operational contracts through 2017 that can move approximately 750,000 to 780,000 acre-feet annually. Beyond that amount, Metropolitan relies on the market for supplemental purchases. Because Metropolitan is experiencing low diversion levels on the CRA, the existing contractual resources are all that is necessary to meet pumping requirements.

The SWP uses low-cost hydroelectric and recovery resources to meet about 50 percent of its energy needs. It relies on the wholesale market and contractual resources with market price risk exposure for as much as 30 to 35 percent of its needs. Because it has a greater exposure to the wholesale market for power, the SWP has been affected by the significant changes in the structure and cost of the wholesale energy market. Even with these cost differences, the average energy cost on the SWP is still well below the market and below what SCE and PG&E charge their largest customers, as shown in Figure 24.

Going forward, staff will continue to monitor risk issues that will affect power supply costs on the CRA and the SWP and investigate and propose potential solutions. As stated in the discussion of CRA energy, in the long term, key contracts will expire in 2017, including Hoover and the SCE Service and Interchange Agreement. Metropolitan's resource mix and costs will likely change, and Metropolitan may face increased exposure to both on- and off-peak wholesale energy prices. Metropolitan will likely also have to address issues of renewable generation and greenhouse gas emissions reduction with regard to CRA operations.

As for the SWP, expiration of resource contracts over the next 7 to 8 years and renewable generation and greenhouse gas emissions reductions are front and center. Identified risks for the CRA and SWP include:

- Contract risk: 2017 contract terminations for the Boulder Canyon Project (Hoover) and the SCE Service and Interchange Agreement. Changes to Metropolitan's CRA power supply portfolio and performance obligations due to changes in terms and/or non-renewal could potentially have significant upward cost impacts on Metropolitan.
- Market risk: fuel and market price risk due to significantly changed Western wholesale energy markets. The Western wholesale energy markets have undergone profound changes, and are now far more vulnerable to severe price spikes and price volatility. The upward trend of wholesale energy prices combined with high levels of market price volatility result in a need for Metropolitan to evaluate ways to manage these risks, including the use financial as well as physical products.
- Operational risk. Recent examples include pumping restrictions at the Banks pumping plant due to environmental and endangered species issues. Potential impacts on the CRA may be realized as well due to such things as Quagga mussel control. These unplanned events will continue to have negative impacts on Metropolitan's power costs by limiting operational flexibility.
- Greenhouse gas emissions reductions and renewable resource development. The state of California is taking a leadership role in reducing greenhouse gas

emissions. A significant contributor to greenhouse gas emissions is the electricity industry. In a 2005 report, the California Energy Commission concluded that the water sector in California is the largest user of energy in the state, accounting for 19 percent of all electricity consumed in the state and 30 percent of non-power plant related natural gas use. Metropolitan and the SWP currently utilize clean, sustainable hydroelectric generation, but Metropolitan and the Department of Water Resources will need to investigate economically reasonable opportunities to reduce greenhouse gas emissions and develop cost-effective renewable energy resources.

- Hyatt-Thermalito relicensing and contractor litigation. DWR's federal license to operate the Oroville Complex—Oroville Dam, Hyatt Power Plant, Thermalito Power Plant, and Thermalito Pumping-Generating Plant, and ancillary facilities—expired January 2007. Relicensing is critical because these facilities generate power used by the SWP to move water to contractors and keep pumping costs low. Proceedings are under way at the Federal Energy Regulatory Commission to approve the continued operations at the Oroville Complex. Not all parties are satisfied with the proposed settlements, and a risk exists that the cost to contractors of relicensing the Oroville Complex increases. Additionally, litigation has been initiated by a coalition of contractors challenging the allocation of costs and benefits from the Oroville Complex, which could increase the cost of the SWP to Metropolitan and other contractors south of the Tehachapis.

The next several years will present many challenges to managing Metropolitan's energy costs on the CRA and the SWP. Metropolitan staff will continue to work with the Board to find solutions to these challenges.