Central Valley Project
Final Cost Allocation Study

Economic Benefits Analysis Appendix

U.S. Department of the Interior January 2020

Mission Statements

The mission of the Department of the Interior is to protect and provide access to our Nation's natural and cultural heritage and honor our trust responsibilities to Indian Tribes and our commitments to island communities.

The mission of the Bureau of Reclamation is to manage, develop, and protect water and related resources in an environmentally and economically sound manner in the interest of the American public.

Table of Contents

Page

List of Attachments

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Chapter 1. Introduction

The economic valuation approach for Federal water resource projects and the Central Valley Project (CVP) Final Cost Allocation Study (CAS) is consistent with the Federal Economic and Environmental Principles and Guidelines for Water and Related Land Resources Implementation Studies (P&G) (Water Resources Council 1983). The P&Gs support the Federal objective of contributing to national economic development in water and related land resources project planning consistent with protecting the nation's environment, pursuant to national environmental statutes, applicable executive orders, and other Federal planning requirements. CVP CAS economic benefits were estimated for the four authorized project purposes that will share in joint costs of the CVP: water supply (including irrigation and municipal and industrial (M&I) water supplies), water quality, flood control, and hydropower.

This Economic Benefits Analysis Appendix to the CVP Final CAS is organized into the following chapters and attachments:

- Chapter 1, *Introduction*, provides a general background of economic benefits estimated for the CAS, including an overview of economic analysis parameters.
- Chapter 2, *Irrigation Water Supply,* describes the irrigation water supply economic benefit estimation methodology and results of the analysis.
- Chapter 3, *Municipal and Industrial Water Supply*, describes the M&I water supply economic benefit estimation methodology and results of the analysis.
- Chapter 4, *Water Quality*, describes the water quality economic benefit estimation methodology and results of the analysis.
- Chapter 5, *Flood Control*, describes the flood control economic benefit estimation methodology and results of the analysis.
- Chapter 6, *Hydropower*, describes the hydropower economic benefit estimation methodology and results of the analysis.
- The *References* section presents a comprehensive list of references used throughout this Appendix.
- The *Economic Benefits Analytical Tool Descriptions Attachment*, presents descriptions of economic analytical tools used to estimate economic benefits.
- The *Forecast of Economic Value of CVP Power 2014-2113 Attachment*, presents methodology and results of analysis to estimate hydropower benefits of the Central Valley Project.

1.1 Economic Analysis Parameters

The estimation of economic benefits presented in this appendix is based on a prospective analysis of the CVP over a 100-year period. The methodology used to estimate economic benefits had the following common elements, except where noted:

- Hydrology outputs from the CalSim 2 model presented in the *Hydrological Modeling Appendix* are used as inputs for the economics models, with the exception of flood control that was based on damages avoided as estimated by the USACE.
- All benefit values reflect 2013 dollars.
- All benefits are based on future conditions expected over the 100-year period of analysis. The economic benefits attributed to each project purpose are assumed to remain constant over the entire period of analysis. It is acknowledged that CVP project operations and related conditions are dynamic and will change over the 100-year period of analysis. However, due to modeling and data limitations, a single year, average condition scenario was used to reflect the prospective period of analysis.
- The benefit estimates used for Separable Costs-Remaining Benefits (SCRB) analysis reflect the present value of annual benefits over the 100-year period of analysis using a discount rate of 3.25 percent.
- Economic benefits are based on a water year type analysis for those purposes dependent on hydrology outputs, namely irrigation, M&I, water quality, and hydropower. (The water year type analysis does not apply to the flood control benefits because those estimates already reflect average annual values across a range of water year types.) Benefits were estimated by water year type (based on the 82-year hydrological record in the CalSim 2 model) and the results of the various water year scenarios were weighted based on the relative distribution in the hydrologic record, which was extended through 2013. Additional information on the water year type analysis is presented below.

1.2 Water Year Analysis

In the CVP, project benefits that are dependent on water supply availability include water supply (principally irrigation and municipal and industrial uses), water quality, and hydropower. Generally, the magnitude of economic benefits attributed to these purposes varies based on the quantity of water available in any given year and on the scarcity value of water across its many uses. As a result, each respective benefit analysis should account for annual fluctuations in water supply availability. In many studies, benefit estimates for water supply-dependent benefits have been calculated using long-term average annual deliveries, which does not account for potential differences in benefits across water year types. As a result, over a 100-year period of analysis, use of a single point estimate for water deliveries may not accurately predict the cumulative impact associated with the range and variability across individual water years. Using an approach which integrates the frequency of water year types into a single point estimate based on a series of runs for each water year type may generate results which may be more representative of long-term conditions. Accordingly, this approach is able to account for the variability of different water supply conditions by estimating benefits separately for each water year type under consideration and appropriately weighting the results to derive average annual benefits.

Water year classifications provide a means to aggregate years with similar hydrologic conditions. Water year classifications have been developed by the State Water Resources Control Board (SWRCB) for several hydrologic basins in California, including the Sacramento Valley, which represents the most applicable measure of hydrologic conditions affecting the CVP. The Sacramento Valley index defines wet, above normal, below normal, dry, and critical water year types.

Conceptually, the weighting of benefits should be consistent with the frequency of the forecasted water year types in the period of analysis, in this case, a 100-year prospective analysis. Forecasting water supply availability over the next 100 years is based on historic hydrologic conditions, which includes the hydrologic record used in the CalSim2 model plus additional water years through the base year used in the CAS (2013). The resulting water year distributions used in the economic benefit analyses is presented in Table 1-1.

Table 1-1: Water Year Classifications (Sacramento Valley Index)

Water Year Type	# Years	Percent
Wet	28	30.43%
Above Normal	13	14.13%
Below Normal	17	18.48%
Dry	21	22.83%
Critical	13	14.13%

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Chapter 2. Irrigation Water Supply

2.1 Introduction & Overview

This chapter presents the economic benefits attributed to CVP irrigation water supplies. The information includes a detailed overview of the Statewide Agricultural Production (SWAP) model, which was used to estimate irrigation benefits, as well as the results of the benefits analysis based on a comparison of with-CVP and without-CVP conditions. This chapter is organized into three main sections:

- **Section 2.1: Introduction & Overview**. This section describes the contents and structure of the appendix. It also presents a general overview of CVP irrigation water supplies, which are critical to agricultural production in the Central Valley of California.
- **Section 2.2: Methodology – SWAP Model**. The CAS uses the SWAP model to quantify the economic benefits of CVP irrigation water supplies. This section provides detailed information about the development, conceptual and analytical framework, geographic coverage, and key sources of input data for SWAP. It also documents the assumptions underlying the SWAP model simulations of the with-CVP and without-CVP scenarios.
- **Section 2.3: Irrigation Benefits Results**. This section presents the results of the SWAP model. Detailed information is presented covering acres in agricultural production, water use, and production value. It also presents estimates of irrigation benefits that are consistent with National Economic Development (NED) guidelines; these benefits are used as inputs to the SCRB cost allocation process.

To provide context to the importance of CVP irrigation water supplies, it is insightful to note the prominence of California's agricultural industry. California has the largest agricultural sector in the U.S with approximately $47.1 billion in crop sales in 2015 (CDFA 2016). Agricultural production in the state is diverse, with over 400 different crops produced. Over a third of the country's vegetables and two-thirds of the country's fruits and nuts are grown in California. The magnitude and diversity of California agriculture supports a substantial export market. In fact, California exported approximately 26 percent of its agricultural production by volume, accounting for $20.69 billion in value, in 2015 (CDFA 2016). Although agricultural production extends across California, the Central Valley is at the center of the State's agricultural industry. The top five counties for agricultural sales in 2015 were Tulare, Kern, Fresno, Monterey and Stanislaus counties. Many of these counties and other important agricultural regions throughout the State are directly served by CVP water supplies.

2.2 Methodology – SWAP Model

The SWAP model is a regional agricultural production and economic optimization model that simulates the decisions of farmers across 93 percent of agricultural land in California. It is the most current in a series of production models of California agriculture developed by researchers at the

University of California at Davis under the direction of Professor Richard Howitt in collaboration with the California Department of Water Resources (DWR). The SWAP model has been subject to peer review and technical details can be found in *"Calibrating Disaggregate Economic Models of Irrigated Production and Water Management"* (Howitt et al. 2012). In addition, SWAP has been used in multiple studies undertaken by the Bureau of Reclamation. Additional details on the application of SWAP to federal planning projects can be found in *"Statewide Agricultural Production (SWAP) Model Update and Application to Federal Feasibility Analysis"* (Bureau of Reclamation 2012). Additional SWAP model documentation can be found in the reference list below. For this analysis, SWAP Model Version 6.1 was used.

2.2.1 SWAP Model Development History

The SWAP model is an improvement and extension of the Central Valley Production Model (CVPM). The CVPM was developed in the early 1990s and was used to assess the impacts of the Central Valley Project Improvement Act (Reclamation and USFWS 1999). The SWAP model allows for greater flexibility in production technology and input substitution than CVPM does, and has been extended to allow for a range of analyses, including interregional water transfers and climate change effects. Its first application was to estimate the economic scarcity costs of water for agriculture in the statewide hydro-economic optimization model for water management in California, CALVIN (Draper et al. 2003). More recently, the SWAP model has been used to estimate the economic losses caused by salinity in the Central Valley (Howitt et al. 2009a), economic losses to agriculture in the Sacramento-San Joaquin Delta (Lund et al. 2007), and economic effects of water shortage to Central Valley agriculture (Howitt et al. 2009b). The model was updated and augmented for use by Bureau of Reclamation in 2012 for use in several ongoing studies of water projects and operations.

2.2.2 SWAP Conceptual Framework

SWAP is a representation of a complex water delivery and farm production system. It is characterized as a non-linear optimization model that reflects farm-level decision making. The theoretical basis of the model is driven primarily by crop demand functions for the primary crops grown in the Central Valley, available water supplies (both surface water and groundwater), and farm production costs and revenues. As with any model, SWAP requires that assumptions and simplifications be made due to the complexities involved in modeling such a large-scale system.

The SWAP model assumes that growers select the crops, water supplies, and other inputs to maximize profit subject to resource constraints, technical production relationships, and market conditions. Growers face competitive markets, thus no one grower can influence crop prices. The competitive market is simulated by maximizing the sum of consumer and producer surplus subject to the following characteristics of production, market conditions, and available resources:

2.2.2.1 Calibration Using Positive Mathematical Programming (PMP)

The SWAP model self-calibrates using a three-step procedure based on PMP (Howitt 1995a) and the assumption that farmers behave as profit-maximizing agents within a competitive market. In a traditional optimization model, profit-maximizing farmers would simply allocate all land, up until resource constraints become binding, to the most valuable crop(s). In other words, a traditional model would have a tendency for overspecialization in production activities relative to what is observed empirically. PMP incorporates information on the marginal production conditions that farmers face, allowing the model to replicate a base year of observed input use and output. Farm- and field-specific conditions that are unobserved in aggregated data may include inter-temporal effects of crop rotation, proximity to processing facilities, management skills, farm-level effects such as risk and input smoothing, and heterogeneity in soil and other physical capital. In the SWAP model, PMP is used to translate these unobservable marginal conditions, in addition to observed average conditions, into an exponential "PMP" cost function. This cost function allows the model to calibrate to a base year of observed input use and output.

The SWAP model assumes additional land brought into production faces an increasing marginal cost of production. The most fertile or lowest cost land is cultivated first; additional land brought into production is of lower "quality" because of poorer soil quality, drainage or other water quality issues, or other factors that cause it to be more costly to farm. This is captured through an exponential land cost function (PMP cost function) for each crop and region. The exponential function is advantageous because it is always positive and strictly increasing, consistent with the hypothesis of increasing land costs. The PMP cost function is both region- and crop-specific, reflecting differences in production across crops and heterogeneity across regions. Functions are calibrated using information from acreage response elasticities and shadow values of calibration and resource constraints. The information is incorporated in such a way that the average cost conditions (the observed cost data) are unaffected.

2.2.2.2 Constant Elasticity of Substitution Production Function

Crop production in the SWAP model is represented by a constant elasticity of substitution (CES) production function for each region and crop with positive acres. In general, a production function captures the relationship between inputs and output. For example, land, labor, water, and other inputs are combined to produce a crop. CES production functions in the SWAP model are specific to each region; thus, regional input use is combined to determine regional production for each crop. The calibration routine in SWAP guarantees that both input use and output match a base year of observed data.

The SWAP model considers four aggregate inputs to produce each crop in each region: land, labor, water, and other supplies. All units are converted into monetary terms, e.g., dollars of labor per acre instead of worker hours. Land is simply the number of acres of a crop in any region. Land costs represent basic land investment, cash overhead, and (when applicable) land rent. Labor costs represent both machinery labor and manual labor. "Other supplies" is a broad category that captures a range of inputs including fertilizer, pesticides, chemicals, capital recovery, and interest on operating capital. Water costs and use per acre vary by crop and region.

The generalized CES production function allows for limited substitution among inputs (Beattie and Taylor 1985). This is consistent with observed farmer production practices (farmers are able to substitute among inputs in order to achieve the same level of production). For example, farmers may substitute labor for chemicals by reducing herbicide application and increasing manual weed control. Or, farmers can substitute labor for water by managing an existing irrigation system more intensively in order to reduce water use. The CES function used in Version 6.1 of the SWAP model is non-nested; thus, the elasticity of substitution is the same between all inputs.

2.2.2.3 Crop Demand Functions

The SWAP model is specified with downward-sloping, California-specific crop demand functions. The demand curve represents consumers' willingness-to-pay for a given level of crop production. With all else constant, as production of a crop increases, the price of that crop is expected to fall. The extent of the price decrease depends on the elasticity of demand or, equivalently, the price flexibility, which is the percentage change in crop price due to a percent change in production. Demand functions are specific to a crop but not to a region.

Therefore, large changes in production in one set of regions can, through the demand-induced price changes, lead to changes in production in other regions.

The SWAP model is specified with linear demand functions. The nature of the demand function for specific commodities can change over time due to tastes and preferences, population growth, changes in income, and other factors. The SWAP model incorporates linear shifts in the demand functions over time due to growth in population and changes in real income per capita. Changes in the demand elasticity itself, resulting from changing tastes and preferences, are not considered in the model, though they can be evaluated by changing demand function parameters in the model's input data.

2.2.2.4 Water Supply and Groundwater Pumping

Total available water for agricultural production is specified on a regional basis in the SWAP model. Each region has six sources of supply, although not all sources are available in every region:

- CVP water service contracts (including Friant-Kern Class 1 water service contracts)
- CVP Sacramento River settlement contracts and San Joaquin River exchange contracts
- Friant Kern Class 2 water service contracts
- SWP entitlement contracts
- Other local surface water
- Groundwater

Data sources and associated calculations are described in *Statewide Agricultural Production (SWAP) Model Update and Application to Federal Feasibility Analysis* (Reclamation 2012). State and Federal project deliveries are estimated from delivery records of DWR and Reclamation. Local surface water supplies are based on DWR estimates and reports of individual water suppliers, and, where necessary, are drawn from earlier studies.

Costs for surface water supplies are compiled from information published by individual water supply agencies. There is no central data source for water prices in California. Agencies that prepared CVP water conservation plans or agricultural water management plans in most cases included water prices and related fees charged to growers. Other agencies publish and/or announce rates on an annual basis. Water prices used in SWAP are intended to be representative for each region, but vary in their level of detail.

Groundwater availability is specified by region-specific maximum pumping estimates. These are determined by consulting the individual districts' records and information compiled by DWR. DWR analysts provided estimates of the actual pumping in the base year and the existing pumping capacity by region. The base assumptions in the SWAP model are used for modeling with-CVP conditions; additional constraints are applied to without-CVP conditions as described below.

The model determines the optimal level of groundwater pumping for each region, up to the capacity limit specified. SWAP or CVPM has also been used interactively with a groundwater model to evaluate short-term and long-term effects on aquifer conditions and pumping lifts.

Pumping costs vary by region depending on depth to groundwater and power rates. The SWAP model includes a routine to calculate the total costs of groundwater. The total cost of groundwater is the sum of fixed, operation and maintenance (O&M), and energy costs.

2.2.2.5 Agricultural Land Use

The SWAP calibrates to observed cropping patterns in the Central Valley. Agricultural land use data in SWAP correspond to the year 2010 and were prepared by DWR analysts. DWR is now developing more detailed annual time series data on agricultural land use, but the current version of the SWAP model calibrates to 2010 as a relatively normal base year.

2.2.2.6 Farm Production Costs

The production of crops involves both fixed and variable costs. Fixed costs represent ownership costs and land and capital equipment, while variable costs include expenditures on farming inputs (e.g., seed, fertilizer, etc.) and labor. Farm production costs data in SWAP are based on crop budgets developed by the University of California Cooperative Extension (UCCE).

2.2.2.7 Farm-Level Revenues

Agricultural revenues realized by farmers are based on crop yields and prices. Representative prices and yields for crops in the SWAP model are based on county agricultural commissioner data.

2.2.2.8 Summary of SWAP Model Inputs and Supporting Data

Table 2-1 summarizes input data and sources used in the SWAP model. All prices and costs in SWAP are in constant 2010 dollars for consistency with the land use data. Post-processing adjustments were made to convert all values to 2013 dollars for use in the CAS.

Table 2-1. SWAP Model Input Data Summary

Input	Source	Notes
Land Use	DWR	Base year 2010
Crop Prices	County Agricultural Commissioners	By proxy crop using 2010-2012 average prices, indexed to 2010 price level

Input	Source	Notes
Crop Yields	UCCE crop budgets	By proxy crop for various years (most recent available)
Interest Rates	UCCE crop budgets	Crop budget interest costs adjusted to year 2010
Land Costs	UCCE crop budgets	By proxy crop for various years (most recent available), in 2010 dollars
Other Supply Costs	UCCE crop budgets	By proxy crop for various years (most recent available), in 2010 dollars
Labor Costs	UCCE crop budgets	By proxy crop for various years (most recent available), in 2010 dollars
Surface Water Costs	Reclamation, DWR, individual districts	By SWAP model region; in 2010 dollars
Groundwater Costs	PG&E, individual districts	Total cost per acre-foot includes fixed, O&M, and energy cost, in 2010 dollars
Irrigation Water	DWR	Average crop irrigation water requirements, in acre-feet per acre.
Available Water	CVPM, DWR, Reclamation, individual districts	By SWAP model region and water supply source
Elasticities	Russo et al. 2008	California estimates

2.2.2.9 Other SWAP Model Assumptions

The following represent key modeling assumptions integrated into the SWAP model:

- Groundwater pumping costs are based on a base electricity rate of $0.22/kwh, pumping efficiency factor of 70 percent, and O&M cost of $0.025/kwh. The base electricity rate was escalated to 2024 using a scalar of 1.266 (reflecting a 26.6 percent increase real electricity rates) The 2024 timeframe was selected in order to be consistent with the power benefits analysis, which is based on forecasted wholesale electricity costs in 2024. Energy costs are based on a blend of agricultural power rates provided by Pacific Gas and Electric Company (PG&E) and forecasts by the California Energy Commission (CEC 2014).
- Elasticity of substitution (inputs) is 0.17.
- Elasticity of supply (acreage response elasticity) reflect long run conditions and varies by crop.

- Crop prices are endogenous in response to population and real income growth. Population growth rate is estimated at 2.5 percent annually. Real income growth is estimated at one percent annually.
- Consumer surplus benefits are excluded from the calculation of benefits. Consumer surplus benefits accrue to society (consumers of agricultural products), rather than agricultural producers. Because the objective of cost allocation is to allocate costs across project purposes, including water supply, which subsequently is passed on to agricultural producers, it was determined that it would not be appropriate to include consumer surplus benefits.

2.2.3 Geographic Coverage (SWAP Regions)

The SWAP model has 27 base regions in the Central Valley. The model is also able to include agricultural areas of the Central Coast, the Colorado River region that includes Coachella, Palo Verde and the Imperial Valley, and San Diego, Santa Ana, and Ventura and the South Coast; however, those regions were not analyzed for the CAS. Figure 2-1 shows the numbered California agricultural areas covered in SWAP. Table 2-2 details the major water users in each of the regions.

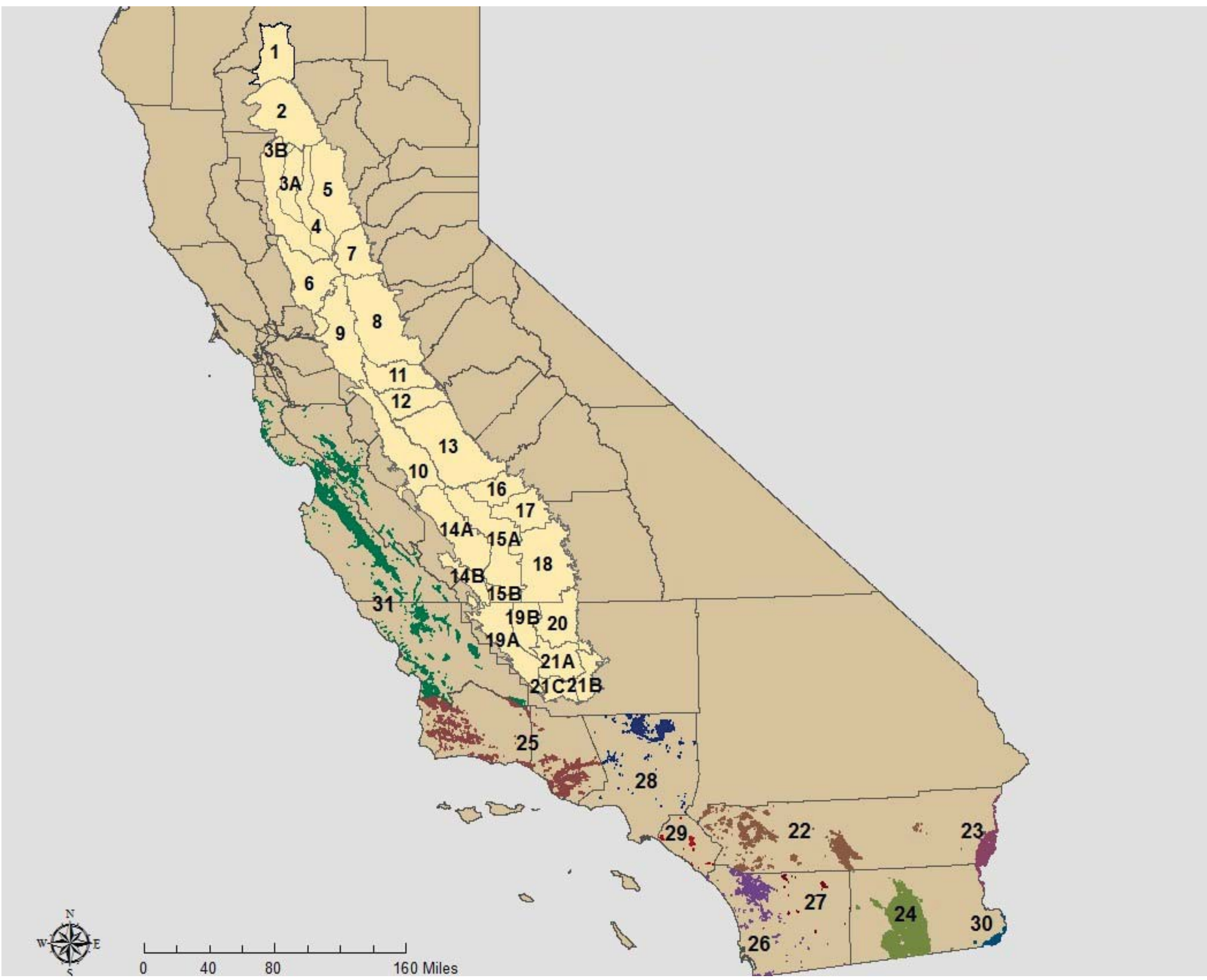

Figure 2-1. SWAP Model Coverage of Agriculture in California

Table 2-2. SWAP Model Regions and Water Users

Region	User
1	CVP Users: Anderson Cottonwood ID, Clear Creek CSD, Bella Vista WD, and misc. Sacramento River water users
2	CVP Users: Corning Canal, Kirkwood WD, Tehama, and misc. Sacramento River water users
3a	CVP Users: Glenn Colusa ID, Provident ID, Princeton-Codora ID, Maxwell ID, and Colusa Basin Drain MWC
3b	Tehama Colusa Canal Service Area. CVP Users: Orland-Artois WD, most of Colusa County, Davis WD, Dunnigan WD, Glide WD, Kanawha WD, La Grande WD, and Westside WD
4	CVP Users: Princeton-Codora-Glenn ID, Colusa IC, Meridian Farm WC, Pelger Mutual WC, RD 1004, RD 108, Roberts Ditch IC, Sartain MWC, Sutter MWC, Swinford Tract IC, Tisdale Irrigation and Drainage Co., and misc. Sacramento River water users
5	Most Feather River Region riparian and appropriative users
6	Yolo and Solano Counties. CVP Users: Conaway Ranch and misc. Sacramento River water users
7	Sacramento County north of American River. CVP Users: Natomas Central MWC, misc. Sacramento River water users, MWC, and Placer County WA
8	Sacramento County south of American River and northern San Joaquin County
9	Direct diverters within the Delta region. CVP Users: Banta Carbona ID, West Side WD, and Plainview
10	Delta Mendota service area. CVP Users: Panoche WD, Pacheco WD, Del Puerto WD, Hospital WD, Sunflower WD, West Stanislaus WD, Mustang WD, Orestimba WD, Patterson WD, Foothill WD, San Luis WD, Broadview, Eagle Field WD, Mercy Springs WD, San Joaquin River Exchange Contractors
11	Stanislaus River water rights: Modesto ID, Oakdale ID, and South San Joaquin ID
12	Turlock ID
13	Merced ID CVP Users: Madera ID, Chowchilla WD, and Gravely Ford
14a	CVP Users: Westlands WD
14b	Southwest corner of Kings County
15a	Tulare Lake Bed. CVP Users: Fresno Slough WD, James ID, Tranquillity ID, Traction Ranch, Laguna WD, and RD 1606

Region	User
15b	Dudley Ridge WD and Devils Den (Castaic Lake)
16	Eastern Fresno County. CVP Users: Friant-Kern Canal, Fresno ID, Garfield WD, and International WD
17	CVP Users: Friant-Kern Canal, Hills Valley ID, Tri-Valley WD, and Orange Cove
18	CVP Users: Friant-Kern Canal, County of Fresno, Lower Tule River ID, Pixley ID, portion of Rag Gulch WD, Ducor, County of Tulare, most of Delano-Earlimart ID, Exeter ID, Ivanhoe ID, Lewis Creek WD, Lindmore ID, Lindsay-Strathmore ID, Porterville ID, Sausalito ID, Stone Corral ID, Tea Pot Dome WD, Terra Bella ID, and Tulare ID
19a	SWP Service Area, including Belridge WSD, Berrenda Mesa WD
19b	SWP Service Area, including Semitropic WSD
20	CVP Users: Friant-Kern Canal. Shafter-Wasco, and South San Joaquin ID
21a	SWP Users and CVP Users served by Cross Valley Canal and Friant-Kern Canal
21b	Arvin Edison WD and portions of Wheeler Ridge–Maricopa WSA
21c	SWP service area: Wheeler Ridge–Maricopa WSD

2.2.4 SWAP Crop Groups

The SWAP model covers 20 different crop groups grown in the Central Valley. For each crop group, a proxy crop is identified, which is intended to be representative of the group in terms water use, costs, and revenues. Crop group definitions and the corresponding proxy crop are shown in Table 2-3.

Table 2-3. SWAP Model Crop Groups

SWAP Definition	Proxy Crop	Other Crops
Almonds and Pistachios	Almonds	Pistachios
Alfalfa	Alfalfa hay	–
Corn	Grain corn	Corn silage
Cotton	Pima cotton	Upland cotton
Cucurbits	Summer squash	Melons, cucumbers, pumpkins

SWAP Definition	Proxy Crop	Other Crops
Dry Beans	Dry beans	Lima beans
Fresh Tomatoes	Fresh tomatoes	–
Grain	Wheat	Oats, sorghum, barley
Onions and Garlic	Dry onions	Fresh onions, garlic
Other Deciduous	Walnuts	Peaches, plums, apples
Other Field	Sudan grass hay	Other silage
Other Truck	Broccoli	Carrots, peppers, lettuce, other vegetables
Pasture	Irrigated pasture	–
Potatoes	White potatoes	–
Processing Tomatoes	Processing tomatoes	–
Rice	Rice	–
Safflower	Safflower	–
Sugar Beet	Sugar beets	–
Subtropical	Oranges	Lemons, misc. citrus, olives
Vine	Wine grapes	Table grapes, raisins

2.2.5 NED Post-Processing Adjustments

The benefits analyses used in the CAS are consistent with NED benefits outlined in the Principles & Guidelines (P&Gs). Although the optimization of the SWAP model are based on the parameters described above, the following NED post-processing adjustments have been applied for the purposes of the CAS:

- The interest rate used in the CAS is 3.25 percent. The short-run variable interest rate and fixed interest rate were both adjusted to reflect the CAS interest rate.
- Normalized prices were applied to basic crops based on USDA data. Normalized prices were calculated based on a five-year average between 2009 and 2013. The basic crops in the model are corn, cotton, dry beans, grain, rice, and sugar beets.
- Five-year average prices were applied to non-basic crops using statewide (California) values for the period 2009 to 2013. The non-basic crops in the model are alfalfa, almonds/pistachios, cucurbits, fresh tomatoes, onion/garlic, other deciduous crops, other

field crops, other truck crops, potatoes, processing tomatoes, safflower, subtropical crops, and vines.

- Estimated irrigation benefits were adjusted to net out the cost of CVP water supplies. Paragraph 8 of Reclamation Manual D&S PEC 01-02, *Project Cost Allocations*, states that the benefits used in the cost allocation should be the same as those used for project justification. For project justification, project water costs are excluded from benefit estimates because they are accounted for in the cost of the project. In the context SWAP, because all water costs are included in the estimate of net revenues for the purposes of optimization, CVP water costs were added back to the estimate of irrigation water supply benefits.
- Irrigation benefits include avoided land fallowing costs attributed to CVP water supplies. Fallowing costs are calculated at $40.12 per acre
- All cost and revenues were adjusted to 2013 dollars using the GDP implicit Price Deflator (IPD)

2.2.6 Model Limitations and Applicability

The SWAP model is an optimization model that makes the best (most profitable) adjustments to water supply and other changes to maximize net revenues. Constraints can be imposed to simulate restrictions on how much adjustment is possible or how fast the adjustment can realistically occur. Nevertheless, an optimization model can tend to over-adjust and minimize costs associated with detrimental changes or, similarly, maximize benefits associated with positive changes.

In addition, SWAP does not explicitly account for the dynamic nature of agricultural production; it provides a point in time comparison between two conditions. This is consistent with the way most economic and environmental impact analysis is conducted, but it can obscure sometimes important adjustment costs. SWAP also does not explicitly incorporate risk or risk preferences (e.g., risk aversion) into its objective function. Risk and variability are handled in two ways. First, the calibration procedure for SWAP is designed to reproduce observed crop mix, so to the extent that crop mix incorporates farmers' risk spreading and risk aversion, the starting, calibrated SWAP base condition will also. Second, variability in water delivery, prices, yields, or other parameters can be evaluated by running the model over a sequence of conditions or over a set of conditions that characterize a distribution, such as a set of water year types.

Ground water is an alternative source to augment local surface, SWP, and CVP water delivery in all SWAP regions. The cost and availability of groundwater therefore has an important effect on how SWAP responds to changes in delivery. However, SWAP is not a groundwater model and does not include any direct way to adjust pumping lifts and unit pumping cost in response to long-run changes in pumping quantities; such modifications must come from an accompanying groundwater analysis.

2.2.7 Other Methodological Considerations

The methodology described above focuses on the SWAP model; however, there are other important methodological considerations in the estimation of CVP water supply benefits, which are described below.

2.2.7.1 With- and Without-CVP Conditions

The evaluation of CVP benefits is based on the change (or difference) between with-CVP and without-CVP conditions. From a hydrologic perspective, available water supplies under with-CVP conditions are modeled using CalSim2; for more information on the CalSim2 modeling prepared for the CAS, refer to the *Hydrological Modeling Appendix*. It is not possible to model without-CVP conditions using CalSim2. Therefore, for the without-CVP scenario, available CVP water supplies were manually adjusted as follows:

- Set CVP water service contracts (including Friant-Kern Class 1 water service contracts) to zero;
- Set Friant Kern Class 2 water service contracts to zero;
- Set CVP Section 215 water to zero;
- Set CVP Sacramento River settlement contractor deliveries as follows:
  - Wet: 88.78%
  - Above Normal: 96.39%
  - Below Normal: 87.00%
  - Dry: 83.84%
  - Critical: 80.14%
- Set San Joaquin River Exchange Contractors deliveries as follows:
  - Wet: 94.98%
  - Above Normal: 87.50%
  - Below Normal: 82.14%
  - Dry: 72.01%
  - Critical: 61.87%

For both the CVP Sacramento River settlement contractors and San Joaquin River Exchange Contractors, it is assumed that they would continue to receive irrigation water pursuant to their water rights in the without-CVP scenario. The proportion of water that these groups receive without the CVP is based on CalSim2 modeling analysis. All other surface water supplies, namely SWP supplies and local supplies, are held constant in the with-CVP and without-CVP scenarios.

Additional considerations related to the without-CVP scenario were required. Specifically, removing all CVP water service contract delivery and a portion of settlement and exchange contract delivery with no assessment of the consequences to historical land development, groundwater depletion, or groundwater cost, results in an analysis that likely understates the benefits of CVP irrigation water. As a result, additional modifications were made relative to groundwater pumping constraints in the without-CVP scenario. It is difficult to estimate available groundwater pumping supplies without the CVP, which represents a significant source of groundwater recharge. In addition, it is not plausible that groundwater supplies without the CVP would be comparable to with-CVP conditions. In the absence of groundwater modeling, it was necessary to develop groundwater assumptions for the without-CVP scenario. For this analysis, groundwater pumping in the without-CVP scenario was generally limited to endogenous with-CVP groundwater pumping levels. In other words, groundwater pumping without the CVP was not allowed to exceed estimated groundwater pumping levels with the CVP in place. It was determined that limiting groundwater pumping in the without-CVP scenario in this manner provides a more reasonable estimate of CVP irrigation water supply benefits.

2.2.7.2 Prospective Period of Analysis – Assumptions

Irrigation benefits are based future conditions expected over the 100-year period of analysis. For this analysis, the prospective period of analysis is based on 2030 conditions unless noted otherwise. This is generally consistent with the level of development modeled by CalSim. Future crop demands are based on shifts over time due to growth in population and real per-capita income. It is acknowledged that agricultural conditions and markets are dynamic and will change over the 100-year period of analysis; however, due to modeling and data limitations, a single year scenario was used to reflect the prospective period of analysis.

2.3 Irrigation Benefits Results

The SWAP model estimates irrigation benefits based on changes in cropping patterns and farm-level production costs and revenues in response to available water supplies under the with-CVP and without-CVP scenarios. This section presents forecasted physical changes in the agricultural landscape attributed to the CVP, namely cropping patterns (irrigated acres) and agricultural water use. Based on these physical changes, irrigation benefits are calculated based on changes in net farm income (profit or producer surplus), surface water and groundwater costs, and land fallowing costs. All monetary values are reported in 2013 dollars.

2.3.1 Acreage in Agricultural Production

Available water supplies directly affect the extent of irrigated acreage in agricultural production. Tables 2-3A and 2-3B show irrigated acreage by crop under the with-CVP and without-CVP scenarios, respectively. With the CVP, there are approximately 6.9 million acres in irrigated agriculture across SWAP regions. Without the CVP, irrigated acreage falls to about 6.3 million acres. In both scenarios, the leading crop type in terms of acreage is almond/pistachios, with nearly 1.1 million acres in production with the CVP.

Table 2-3A. Irrigated Acres, by Crop and Water Year Type, With-CVP Conditions (acres)

Crops	Wet	Above Normal	Below Normal	Dry	Critical	Average (Wgt)
Alfalfa	670,967	671,095	670,978	669,550	663,635	**669,628**
Almond/Pistachio	1,084,988	1,085,071	1,084,956	1,082,687	1,070,906	**1,082,479**

Crops	Wet	Above Normal	Below Normal	Dry	Critical	Average (Wgt)
Corn	730,027	730,098	730,086	729,161	721,234	**728,608**
Cotton	284,726	284,734	284,730	284,571	282,673	**284,402**
Cucurbits	108,925	108,926	108,925	108,921	108,915	**108,923**
Dry Beans	75,698	75,710	75,709	75,657	75,409	**75,652**
Fresh Tomato	36,861	36,861	36,861	36,859	36,853	**36,860**
Grain	368,501	366,437	367,263	365,304	357,809	**365,740**
Onion, Garlic	64,429	64,431	64,431	64,417	64,383	**64,421**
Other Deciduous	639,245	639,256	639,251	639,101	638,727	**639,142**
Other Field	564,952	564,990	564,991	564,772	561,883	**564,490**
Other Truck	206,380	206,381	206,381	206,357	206,256	**206,357**
Pasture, Irrigated	267,983	268,188	267,851	266,259	265,179	**267,198**
Potato	16,872	16,872	16,872	16,872	16,871	**16,872**
Process Tomato	318,409	318,435	318,437	318,346	317,632	**318,294**
Rice	567,957	569,430	569,177	563,115	556,753	**565,702**
Safflower	37,356	37,355	37,364	37,361	37,328	**37,355**
Sugar Beets	592	592	592	592	591	**592**
Subtropical	275,750	275,753	275,752	275,708	275,534	**275,710**
Vineyard	612,462	612,465	612,471	612,425	612,237	**612,424**
Total	**6,933,078**	**6,933,080**	**6,933,080**	**6,918,033**	**6,870,808**	**6,920,845**

Table 2-3B. Irrigated Acres, by Crop and Water Year Type, Without-CVP Conditions (acres)

Crops	Wet	Above Normal	Below Normal	Dry	Critical	Average (Wgt)
Alfalfa	621,155	621,318	621,649	620,572	638,324	**623,562**

Crops	Wet	Above Normal	Below Normal	Dry	Critical	Average (Wgt)
Almond/Pistachio	953,656	993,812	1,028,560	1,052,042	1,059,753	**1,010,625**
Corn	555,402	595,329	605,984	638,509	687,447	**608,023**
Cotton	236,093	236,116	236,535	238,585	279,192	**242,837**
Cucurbits	106,556	108,030	108,121	108,440	108,891	**107,814**
Dry Beans	67,418	66,987	65,984	62,512	66,944	**65,905**
Fresh Tomato	36,682	36,773	36,783	36,807	36,835	**36,764**
Grain	291,693	292,953	296,244	294,951	360,526	**303,182**
Onion, Garlic	56,358	60,008	60,174	63,239	64,149	**60,251**
Other Deciduous	626,180	635,240	635,719	636,913	637,661	**633,296**
Other Field	517,453	519,372	518,784	512,687	525,686	**518,045**
Other Truck	203,107	204,900	205,086	205,855	206,354	**204,812**
Pasture, Irrigated	210,857	208,819	211,678	216,537	231,127	**214,882**
Potato	15,418	16,172	16,247	16,640	16,881	**16,164**
Process Tomato	235,279	235,382	283,861	308,243	315,591	**272,277**
Rice	509,973	493,339	485,432	478,014	456,660	**488,258**
Safflower	37,009	37,165	37,246	37,150	37,331	**37,153**
Sugar Beets	588	590	593	596	594	**592**
Subtropical	264,682	270,207	270,609	273,443	274,757	**269,982**
Vineyard	575,224	591,523	600,048	608,176	611,150	**594,714**
Total	**6,120,784**	**6,224,034**	**6,325,339**	**6,409,911**	**6,615,852**	**6,309,136**

Table 2-3C shows the change in irrigated acreage between the with-CVP and without-CVP scenarios. On average, approximately 612,000 additional acres are irrigated with the CVP in place. In the without-CVP scenario, irrigated agriculture is supported by local and state surface water supplies and groundwater in lieu of CVP water.

Table 2-3C. Irrigated Acres, by Water Year Type, Summary (acres)

Scenario	Wet	Above Normal	Below Normal	Dry	Critical	Average (Wgt)
With-CVP	6,933,078	6,933,080	6,933,080	6,918,033	6,870,808	**6,920,845**
Without-CVP	6,120,784	6,224,034	6,325,339	6,409,911	6,615,852	**6,309,136**
Difference	***812,295***	***709,046***	***607,741***	***508,122***	***254,956***	***611,710***

2.3.2 Agricultural Production Value

The gross value of agricultural production is based on the quantity and price of crops produced. Tables 2-4A and 2-4B show agricultural production value under the with-CVP and without-CVP scenarios, respectively. With the CVP in place, the value of agricultural production across SWAP regions is estimated at $25.7 billion, which is greater than without the CVP ($24.3 billion). The prominent crops supported by the CVP, as measured by annual production value, are almond/pistachio ($5.3 billion), other deciduous crops ($4.5 billion), and vine crops ($4.4 billion).

Table 2-4A. Agricultural Production Values, by Crop and Water Year Type, With-CVP Conditions ($)

Crops	Wet	Above Normal	Below Normal	Dry	Critical	Average (Wgt)
Alfalfa	$1,021,207,573	$1,021,367,591	$1,021,222,405	$1,019,250,151	$1,011,925,345	**$1,019,474,466**
Almond, Pistachio	$5,356,942,801	$5,357,322,198	$5,356,798,926	$5,344,603,228	$5,286,858,808	**$5,344,249,829**
Corn	$891,561,012	$891,646,127	$891,629,733	$890,520,610	$881,205,149	**$889,884,931**
Cotton	$385,220,436	$385,231,198	$385,226,121	$385,011,624	$382,449,765	**$384,783,840**
Cucurbits	$1,132,976,552	$1,132,986,499	$1,132,983,751	$1,132,935,612	$1,132,872,950	**$1,132,955,302**
Dry Beans	$91,337,023	$91,350,598	$91,348,306	$91,287,407	$91,013,194	**$91,283,942**
Fresh Tomato	$427,722,049	$427,723,214	$427,721,278	$427,694,037	$427,633,326	**$427,703,139**
Grain	$295,367,758	$293,981,746	$294,534,368	$292,778,857	$285,396,971	**$293,017,986**
Onion, Garlic	$267,749,135	$267,756,984	$267,756,519	$267,704,072	$267,576,600	**$267,716,941**
Other Deciduous	$4,510,098,350	$4,510,166,881	$4,510,134,637	$4,509,045,015	$4,506,370,450	**$4,509,347,511**

Crops	Wet	Above Normal	Below Normal	Dry	Critical	Average (Wgt)
Other Field	$433,265,925	$433,295,505	$433,296,404	$433,128,696	$430,889,504	**$432,908,620**
Other Truck	$1,041,957,649	$1,041,964,990	$1,041,964,150	$1,041,841,325	$1,041,330,680	**$1,041,844,740**
Pasture, Irrigated	$127,955,605	$128,054,886	$127,893,245	$127,130,429	$126,615,246	**$127,580,329**
Potato	$106,641,603	$106,641,677	$106,641,633	$106,640,545	$106,635,786	**$106,640,556**
Process Tomato	$1,066,582,097	$1,066,664,583	$1,066,671,599	$1,066,372,771	$1,064,088,400	**$1,066,210,144**
Rice	$1,029,261,016	$1,031,922,559	$1,031,468,297	$1,020,572,197	$1,009,104,697	**$1,025,213,252**
Safflower	$23,670,902	$23,670,406	$23,676,161	$23,674,530	$23,653,566	**$23,670,183**
Sugar Beets	$1,381,912	$1,381,929	$1,381,904	$1,381,691	$1,381,106	**$1,381,749**
Subtropical	$3,153,651,771	$3,153,693,218	$3,153,683,774	$3,153,172,124	$3,151,167,061	**$3,153,202,949**
Vineyard	$4,373,193,167	$4,373,217,421	$4,373,250,281	$4,372,905,720	$4,371,630,075	**$4,372,920,660**
Total	**$25,737,744,338**	**$25,740,040,208**	**$25,739,283,492**	**$25,707,650,641**	**$25,599,798,679**	**$25,711,991,067**

Table 2-4B. Agricultural Production Values, by Crop and Water Year Type, Without-CVP Conditions ($)

Crops	Wet	Above Normal	Below Normal	Dry	Critical	Average (Wgt)
Alfalfa	$944,383,041	$944,800,512	$945,357,236	$943,659,881	$972,361,236	**$948,410,282**
Almond, Pistachio	$4,646,717,886	$4,881,208,873	$5,054,514,471	$5,188,423,585	$5,233,011,606	**$4,961,726,985**
Corn	$673,511,361	$723,544,218	$736,841,988	$777,727,609	$839,131,822	**$739,479,244**
Cotton	$319,719,928	$319,748,772	$320,319,056	$323,080,288	$377,747,588	**$328,801,201**
Cucurbits	$1,108,088,973	$1,123,568,586	$1,124,526,981	$1,127,880,091	$1,132,613,150	**$1,121,297,565**
Dry Beans	$80,745,821	$80,210,907	$78,967,307	$74,720,900	$80,484,717	**$78,929,185**
Fresh Tomato	$425,055,900	$426,435,761	$426,575,255	$426,952,147	$427,426,885	**$426,299,584**
Grain	$226,906,325	$227,925,870	$230,236,392	$228,991,137	$286,724,261	**$236,594,020**

Crops	Wet	Above Normal	Below Normal	Dry	Critical	Average (Wgt)
Onion, Garlic	$234,381,718	$250,422,592	$251,159,656	$262,803,629	$266,604,657	**$250,790,680**
Other Deciduous	$4,413,398,164	$4,480,796,859	$4,484,292,756	$4,493,158,836	$4,498,716,637	**$4,466,287,782**
Other Field	$396,958,408	$398,404,105	$397,944,735	$393,283,597	$403,256,783	**$397,395,959**
Other Truck	$1,025,721,110	$1,034,613,227	$1,035,541,052	$1,039,391,616	$1,041,832,999	**$1,034,189,878**
Pasture, Irrigated	$100,668,340	$99,686,398	$101,053,728	$103,353,914	$110,241,489	**$102,566,614**
Potato	$97,065,040	$102,030,893	$102,523,678	$105,112,800	$106,703,160	**$101,974,641**
Process Tomato	$777,269,520	$777,655,400	$945,987,447	$1,031,639,774	$1,057,329,042	**$906,148,257**
Rice	$924,404,718	$894,341,629	$880,059,465	$866,582,412	$827,976,170	**$885,135,615**
Safflower	$23,458,799	$23,554,912	$23,606,083	$23,545,388	$23,659,285	**$23,547,695**
Sugar Beets	$1,372,598	$1,377,885	$1,383,674	$1,391,748	$1,386,046	**$1,381,664**
Subtropical	$3,027,669,130	$3,090,417,720	$3,095,011,878	$3,127,337,331	$3,142,310,755	**$3,087,933,558**
Vineyard	$4,093,668,975	$4,216,387,610	$4,280,151,413	$4,341,141,953	$4,363,519,825	**$4,240,099,079**
Total	**$23,541,165,754**	**$24,097,132,729**	**$24,516,054,251**	**$24,880,178,636**	**$25,193,038,114**	**$24,338,989,487**

Table 2-4C shows the change in gross agricultural production value between the with-CVP and without-CVP scenarios. The CVP supports an additional $1.4 billion in production value compared to without-CVP conditions on average. This is driven by additional acreage in agricultural production, in conjunction with shifts to higher-value crops.

Table 2-4C. Agricultural Production Values, by Water Year Type, Summary ($)

Scenario	Wet	Above Normal	Below Normal	Dry	Critical	Average (Wgt)
With-CVP	$25,737,744,338	$25,740,040,208	$25,739,283,492	$25,707,650,641	$25,599,798,679	**$25,711,991,067**
Without-CVP	$23,541,165,754	$24,097,132,729	$24,516,054,251	$24,880,178,636	$25,193,038,114	**$24,338,989,487**
Difference[1]	***$2,196,578,584***	***$1,642,907,479***	***$1,223,229,241***	***$827,472,005***	***$406,760,564***	***$1,373,001,580***

1. Difference reflects difference between with-CVP and without-CVP conditions

2.3.3 Agricultural Net Revenues

From a NED perspective, *net* agricultural revenues (or profits) associated with agricultural production are reflective of economic benefits. In this context, net revenues are calculated as gross revenues less fixed and variable production costs (other than water costs). Table 2-5 show net revenues in the with-CVP and without-CVP scenarios. On average, net agricultural revenues across SWAP regions is estimated at approximately $6.8 billion annually with the CVP and $6.3 billion without the CVP. With the CVP, farmers are expected to realize about $496.6 million in additional profits compared to without-CVP conditions.

Table 2-5. Agricultural Net Revenues, by Water Year Type, Summary ($)

Scenario	Wet	Above Normal	Below Normal	Dry	Critical	Average (Wgt)
With-CVP	$6,804,051,297	$6,804,578,903	$6,804,032,747	$6,790,796,345	$6,755,523,737	**$6,794,239,370**
Without-CVP	$5,986,641,460	$6,217,583,639	$6,369,793,159	$6,514,279,497	$6,602,832,917	**$6,297,607,641**
Difference [1]	***$817,409,837***	***$586,995,264***	***$434,239,589***	***$276,516,848***	***$152,690,820***	***$496,631,729***

1. Difference reflects difference between with-CVP and without-CVP conditions

2.3.4 Agricultural Water Use

Changes in agricultural water use (and related costs) also represent a major factor in the estimation of irrigation benefits. Tables 2-6A and 2-6B show agricultural water use (both surface water and groundwater) under the with-CVP and without-CVP scenarios, respectively. With the CVP, agricultural water use totals about 21.4 million AF per year, comprised mainly by surface water (13.7 million AF), supplemented by about 7.7 million AF of groundwater, on average. Without the CVP, there is a decline in agricultural water use to 19.2 million AF, primarily due to land fallowing and limits on groundwater availability.

Table 2-6A. Agricultural Water Use, by Source and Water Year Type, With-CVP Conditions (AF)

Water Type	Wet	Above Normal	Below Normal	Dry	Critical	Average (Wgt)
Surface Water	14,629,640	14,102,599	13,754,862	13,163,357	11,999,000	**13,687,048**
Groundwater	6,816,781	7,351,101	7,691,034	8,205,010	9,223,235	**7,710,807**
Total	**21,446,421**	**21,453,700**	**21,445,896**	**21,368,367**	**21,222,235**	**21,397,855**

Table 2-6B. Agricultural Water Use, by Source and Water Year Type, Without-CVP Conditions (AF)

Water Type	Wet	Above Normal	Below Normal	Dry	Critical	Average (Wgt)
Surface Water	11,827,810	11,575,908	11,468,196	11,186,185	10,711,728	**11,421,574**
Groundwater	6,878,441	7,424,578	7,771,164	8,278,480	9,246,889	**7,774,876**
Total	**18,706,251**	**19,000,486**	**19,239,360**	**19,464,665**	**19,958,618**	**19,196,450**

Table 2-6C shows the difference in agricultural water use between the with-CVP and without-CVP scenarios. With the CVP, surface water use increases by about 2.3 million AF and groundwater use decreases slightly by about 64,000 AF compared to without-CVP conditions. As expected, the reliance of groundwater in both scenarios becomes more prominent as hydrological conditions become drier, which reduces the quantity of surface water available.

Table 2-6C. Agricultural Water Use, by Source and Water Year Type, Summary (AF)

Scenario	Wet	Above Normal	Below Normal	Dry	Critical	Average (Wgt)
Surface Water						
With-CVP	14,629,640	14,102,599	13,754,862	13,163,357	11,999,000	**13,687,048**
Without-CVP	11,827,810	11,575,908	11,468,196	11,186,185	10,711,728	**11,421,574**
Difference [1]	***2,801,830***	***2,526,691***	***2,286,666***	***1,977,171***	***1,287,272***	***2,265,474***
Groundwater						
With-CVP	6,816,781	7,351,101	7,691,034	8,205,010	9,223,235	**7,710,807**
Without-CVP	6,878,441	7,424,578	7,771,164	8,278,480	9,246,889	**7,774,876**
Difference [1]	***-61,660***	***-73,478***	***-80,130***	***-73,470***	***-23,654***	***-64,069***

1. Difference reflects difference between with-CVP and without-CVP conditions

2.3.5 Surface Water Costs

Changes in the quantity and type of agricultural water use directly affect water costs incurred by farmers. Table 2-7 shows the difference in surface water costs between the with-CVP and without-CVP scenarios excluding the cost of CVP water supplies, which are not considered for the purposes of estimating project benefits. As explained above, surface water use increases with the CVP; accordingly, surface water costs also increase. However, when excluding CVP water supplies, other surface water costs decrease with the CVP compared to without the CVP. On average, other surface water supplies cost farmers approximately $267.6 million annually with the CVP, compared to $286.8 million without the CVP. This reduction in costs, -$19.2 million, represents a benefit to growers served by CVP water supplies.

Table 2-7. Surface Water Cost, by Water Year Type, Summary ($) [1]

Scenario	Wet	Above Normal	Below Normal	Dry	Critical	Average (Wgt)
With-CVP	$283,512,325	$272,063,753	$268,324,043	$259,578,649	$240,916,208	**$267,604,958**
Without-CVP	$305,954,440	$293,523,457	$289,740,987	$275,175,462	$253,574,585	**$286,773,582**
Difference [2]	***-$22,442,114***	***-$21,459,704***	***-$21,416,944***	***-$15,596,813***	***-$12,658,377***	***-$19,168,624***

1. Excludes CVP water costs

2. Difference reflects difference between with-CVP and without-CVP conditions

2.3.6 Groundwater Pumping Costs

Groundwater represents an alternative water source available to growers in lieu of surface water supplies. Groundwater use declines with the CVP as more surface water becomes available; however, due to constraints on groundwater pumping in the without-CVP scenario, the difference in groundwater pumping costs between the two scenarios is minor. Table 2-8 shows the difference in groundwater costs between the with-CVP and without-CVP scenarios. With the CVP, groundwater pumping costs are estimated to be about $796.6 million annually, while without the CVP, groundwater costs are $801 million annually. This represents a savings in groundwater pumping costs of $4.4 million annually with the CVP.

Table 2-8. Groundwater Pumping Cost, by Water Year Type, Summary ($)

Scenario	Wet	Above Normal	Below Normal	Dry	Critical	Average (Wgt)
With-CVP	$660,429,298	$746,117,644	$801,110,890	$874,070,734	$1,009,171,119	**$796,586,579**
Without-CVP	$665,161,403	$751,501,969	$806,769,265	$878,214,085	$1,010,444,126	**$800,958,834**
Difference [1]	***-$4,732,105***	***-$5,384,325***	***-$5,658,375***	***-$4,143,351***	***-$1,273,007***	***-$4,372,255***

1. Difference reflects difference between with-CVP and without-CVP conditions

2.3.7 Land Fallowing Costs

There are also costs associated with fallowing land. These costs are typically attributed to maintenance activities, such as weed control. With the CVP, additional acreage is put into agricultural production, resulting in fewer acres being fallowed compared to without-CVP conditions. Table 2-9 shows the cost savings (avoided land fallowing costs) under the with-CVP scenario. On average, land fallowing costs decline by about $24.5 million annually with the CVP.

Table 2-9. Land Fallowing Costs, by Water Year Type, Summary ($)

Scenario	Wet	Above Normal	Below Normal	Dry	Critical	Average (Wgt)
With-CVP	-$32,591,473	-$28,448,873	-$24,384,224	-$20,387,239	-$10,229,515	**-$24,543,453**
Without-CVP	--	--	--	--	--	**--**
Difference [1]	***-$32,591,473***	***-$28,448,873***	***-$24,384,224***	***-$20,387,239***	***-$10,229,515***	***-$24,543,453***

1. Difference reflects difference between with-CVP and without-CVP conditions

2.3.8 Summary of Irrigation Water Supply Benefits

The economic benefits associated with CVP irrigation water supplies reflect the additional profit (producer surplus) realized by farmers across SWAP regions. This benefit is comprised of four components: net income, surface water costs, groundwater pumping costs, and land fallowing costs. Specifically, the calculation of the irrigation benefits in SWAP is calculated using the following formula (where the change reflects the difference between with-CVP and without-CVP conditions):

Change in net income

less change in surface water costs

less change in groundwater costs

less change in land fallowing costs

____

= CVP Irrigation Benefits

Table 2-10 displays estimated irrigation benefits attributed to the CVP. Average irrigation benefits are estimated to be $544.7 million annually. The greatest benefits occur in wet years ($877.2 million annually) based on the relatively high quantity of CVP surface water that is delivered. Conversely, the lowest benefits occur in dry years ($176.9 million annually).

Table 2-10. Economic Benefits of CVP Irrigation Water Supplies, by Water Year Type ($) [1]

Category	Wet	Above Normal	Below Normal	Dry	Critical	Average (Wgt)
Net Income	$817,409,837	$586,995,264	$434,239,589	$276,516,848	$152,690,820	**$496,631,729**
SW Costs [2]	-$22,442,114	-$21,459,704	-$21,416,944	-$15,596,813	-$12,658,377	**-$19,168,624**
GW Costs	-$4,732,105	-$5,384,325	-$5,658,375	-$4,143,351	-$1,273,007	**-$4,372,255**
Fallowing Costs	-$32,591,473	-$28,448,873	-$24,384,224	-$20,387,239	-$10,229,515	**-$24,543,453**
Total	**$877,175,528**	**$642,288,166**	**$485,699,131**	**$316,644,252**	**$176,851,718**	**$544,716,061**

1. Benefits reflects difference between with-CVP and without-CVP conditions

2. Excludes CVP water costs

For the CAS, annual irrigation benefits are capitalized over the 100-year period of analysis using a 3.25 percent interest rate. The present value of CVP irrigation benefits is $16,076,140,223.

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Chapter 3. Municipal and Industrial Water Supply

3.1 Introduction

This appendix describes the analytical methods the Central Valley Project Cost Allocation Study (CAS) team used to estimate Municipal and Industrial (M&I) water supply benefits of the Central Valley Project (CVP) and presents the results. The CAS used two models to estimate (M&I) benefits: 1) the Least Cost Planning Simulation Model (LCPSIM) and 2) the Other Municipal Water Economics Model (OMWEM). LCPSIM was used to estimate CVP M&I water supply benefits in the San Francisco Bay Area and OMWEM estimated CVP M&I benefits for the Central Valley.

3.2 Methodology

This section provides information on the methodology and analytical framework of LCPSIM and OMWEM, including information on assumptions, input data, and results within the context of the CVP-CAS.

3.2.1 LCPSIM in the Central Valley Project Cost Allocation Study

The LCPSIM was developed by the State of California's Department of Water Resources (DWR) to estimate the benefits of improving M&I water service reliability for California's South Coast and South San Francisco Bay Regions. For the CAS, LCPSIM only considers the South Bay Region as there are no M&I CVP contractors in the South Coast Region.

LCPSIM is an annual time-step urban water service system simulation/optimization model. Its objective is to find the least-cost water management strategy for a region/district, given the demand and available supplies. It uses shortage management measures, including the use of regional carryover storage, water market transfers, contingency conservation, and shortage allocation rules to reduce costs and losses associated with shortage events. It also considers the adoption of long-term demand reduction and supply augmentation measures that reduce the frequency, magnitude, and duration of shortage events.

A shortage event is the most direct consequence of water service system unreliability. A shortage event may occur when residential users or businesses have an established lifestyle or level of economic production based on expected availability of water that is not met in a particular year or sequence of years. For the CAS, the costs of these shortage events are calculated in LCPSIM and OMWEM by estimating the area under the demand curve that is lost by water users consuming less water than expected; it is assumed that demand is best represented by a constant price elasticity specification with a price elasticity coefficient equal to -0.2.

Assuming that long-term demand reduction and supply augmentation measures are adopted in order of cost, with lowest cost measures adopted first, the models solve for the water management strategy that minimizes the sum of the total annual cost of the adopted long-term reliability enhancement measures and the annual shortage costs and losses remaining after their adoption (Figure 1). Beyond the least-cost point shown, the cost of additional reliability enhancement exceeds the avoided costs and losses resulting from foregone use. At any lower level of reliability enhancement, the expected costs and losses from foregone use exceed the costs to enhance reliability. The value of the availability of supply provided by the CVP can be determined from the change it produces (relative to a without-CVP scenario) in this least-cost mix of demand and supply measures and shortages.

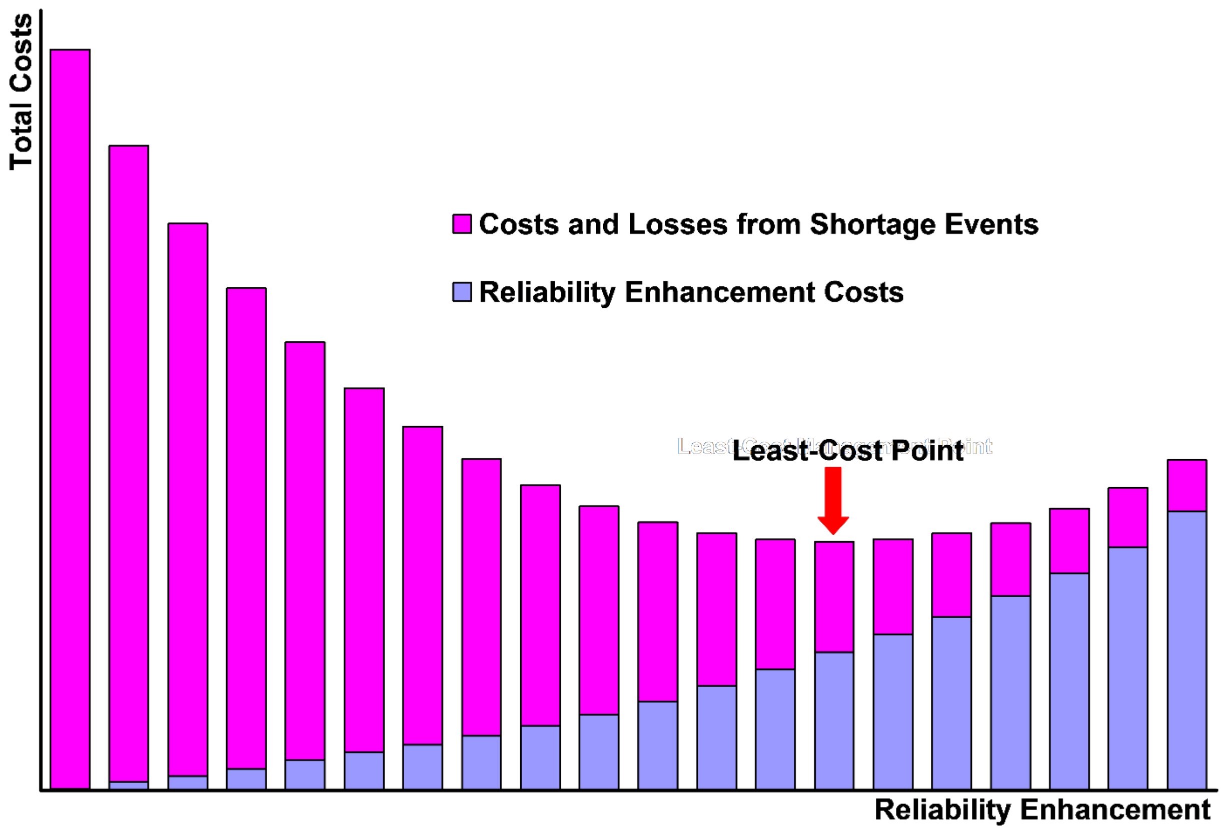

Figure 3-1. Least Cost Point – Optimizing Shortage Costs/Losses and Reliability Augmentation (DWR 2010).

3.2.1.1 LCPSIM Coverage for CVP-CAS

The CVP M&I water service contractors modeled in the LCPSIM include: Contra Costa Water District (CCWD), East Bay Municipal Utility District (EMMUD), Santa Clara Valley Water District (SCVWD), and the San Benito County Water District (SBCWD). For the CAS, the majority of State Water Project (SWP) M&I water contractors and deliveries were not modeled in LCPSIM. The exception is the SCVWD as they receive CVP and SWP water. Removing SWP M&I water deliveries ensures that the LCPSIM optimization process will not consider SWP supplies allowing the costs associated with the without-CVP scenario to be assigned to only to CVP contractors.

3.2.1.2 Water Supply Modeling Assumptions (LCPSIM and OMWEM)

Both LCPSIM and OMWEM use output from the CALSIM II operations model to estimate deliveries in both project scenarios (with- and without-CVP). Water delivery data from the CALSIM II modeling is the only difference between each scenario and is the basis for the changes in economic costs. 2030 CVP M&I contractor water supply portfolios assumed in the CAS were developed from Urban Water Management Plans and CALSIM II modeled water rights and CVP project water. In both the with-CVP scenario and without-CVP scenario, each CVP M&I contractor's local water supplies and CALSIM II modeled water rights are included in the analysis. Only in the with-CVP alternative are the CALSIM II modeled project water deliveries included.

3.2.1.3 LCPSIM Contractor Demand

Table 3-1 below displays the year 2030 CVP M&I contract quantities and demands for each contractor modeled in LCPSIM for the CVP-CAS. There are a few important points to consider in regard to the assumed 2030 demand levels used for this study:

- 2030 demands sourced from CVP M&I contractor's 2010 Urban Water Management Plan (UWMP), if available
- 2030 demands sourced from the Bureau of Reclamation's Central Valley Project M&I Water Shortage Policy Draft Environmental Impact Statement (2014), if UWMP is not available
- The 2030 demands published in the UWMPs are assumed to be compliant with the "20% by 2020" legislation, which refers to conservation criteria
- When an UWMP accounts for additional conservation as part of 2030 supply, this is reflected in OMWEM as a demand reduction instead of as new supply

Table 3-1. LCPSIM Modeled Demands in 2030

CVP M&I Contractor	2030 CVP Contract Quantities (AF)	2030 Demands from UWMP (AF)
Contra Costa Water District	195,000	215,471
East Bay Municipal Utilities District	133,000	304,000
Santa Clara Valley Water District	219,400	409,370
San Benito County Water District	8,250	11,583

3.2.1.4 LCPSIM Contractor Supply

Table 3-2 below displays the CVP M&I contractor non-CVP supplies for a below normal or better water year and a dry or critical water year modeled in LCPSIM. There are some important points to consider in regard to the assumed non-project supplies used for this study:

- Local supplies expected to be available in the year 2030 are based on information from the UWMPs
- LCPSIM uses the 2030 "normal" year supplies reported in the UWMPs to represent the 2030 supplies in wet, above normal, and below normal water year types
- LCPSIM uses the "multiple-year drought" supplies reported in the UWMPs to represent the 2030 supplies in dry and critical water year types

Table 3-2. LCPSIM Assumed 2030 Non-CVP Supplies

CVP M&I Contractor	Non-CVP 2030 Supplies in Below Normal or Better Water Year Type (AF)	Non-CVP 2030 Supplies in Dry or Critical Water Year Type (AF)
Contra Costa Water District	44,800	32,400
East Bay Municipal Utilities District	19,000	19,000
Santa Clara Valley Water District	246,830	179,980
San Benito County Water District	1,170	1,170

3.2.1.5 Water Transfers

For the CAS study it is assumed water transfers will not occur without the CVP in place. There are two primary reasons for this: 1) without the CVP in place, transfers would most likely come from agricultural contractors, but since the study is not accounting for these potential/hypothetical transfers on the agricultural side, it was assumed that the they also would not occur on the M&I side and 2) even if water was available to transfer, there would significant infrastructure constraints that would hinder deliveries. The removal of water transfers forces LCPSIM to employ other demand reduction/supply augmentation options in order to balance demand and supply or to incur more shortage costs.

3.2.1.6 LCPSIM limitations

The results presented below are best estimates based on various assumptions and best available data. It is believed that the estimate of benefits derived using the LCPSIM is reasonable and useful for the purposes of measuring avoided costs of having the CVP in place. Potential limitations of LCPSIM include:

- LCPSIM is not appropriate for individual water agency management decisions because of the simplifying assumptions it makes about regional system operations.
- Because LCPSIM is used to optimize regional economic efficiency from a statewide perspective, LCPSIM results may not reflect decisions made by local water agencies that are based on their cost perspective. Also, local planning decisions are likely to be influenced by local cost effectiveness and political concerns as well as additional factors of importance to regional water agency managers and water users that are not necessarily aligned with the LCPSIM objective.
- LCPSIM uses regional operations studies for local imported supplies to obtain annual delivery information. Regional water supply sources that are not modeled on a year-to-year basis are assumed to be available at their average year values.
- LCPSIM determines its reliability benefits estimates on the basis of a risk-neutral view of risk management. Risk-averse management (risk minimization) by regional agencies–which has been the predominant mode–might result in the justification of more costly water management measures than under the risk neutral assumption.
- LCPSIM is operated on an annual basis. Therefore, it does not simulate seasonal water decisions.
- Base urban use amounts are not reduced in LCPSIM in response to the higher urban user water prices that can be anticipated as regions use water pricing to offset water reliability cost increases.

3.2.2 OMWEM in the Central Valley Project Cost Allocation Study

OMWEM simulates individual water contractor's decision making based on 2030 development conditions using publicly available information. The majority of the water demand and supply data were taken from contractors' Urban Water Management Plans. OMWEM analyzes the economic benefits of the M&I water supply for contractors by minimizing total costs of meeting annual M&I water demands, per contractor, and subject to constraints. These costs include conveyance and operations costs, existing supply and new permanent supply costs, transfer or other option costs, local surface and groundwater operations costs, end-user shortage costs, and lost water sales revenues. OMWEM was revised for the CAS study to include only CVP M&I water contractors in the Sacramento and San Joaquin Valleys of California.

Operating on an annual time step over the 1922 to 2003 hydrologic period, the model uses 1) contract delivery data (which is modeled in CALSIM II), 2) local water supply information, and 3) imported water information (if applicable) to simulate the decision making of each individual contractor as it attempts to meet its 2030 water demand levels at the lowest economic cost. When demand exceeds supply, the model will compute the economic cost of each water contractor as it attempts to either use local stored supplies, purchase or transfer water on the market, or short its customers. If these shortages happen frequently over the hydrologic period, an individual contractor may choose to invest in additional fixed-yield supply. This is represented in OMWEM as a trade-off between incurring shortage costs and investing in additional fixed-yield supply. As in LCPSIM, shortage costs are calculated in OMWEM using a -0.2 constant elasticity of demand function. The retail water price and the 2030 demand level of a contractor define one point on its demand function, wherein the slope is defined by the price elasticity.

Within the OMWEM model, individual CVP M&I contractors were grouped into two main regions, the Sacramento Valley and San Joaquin Valley. The with-CVP and without-CVP scenarios for both regions were estimated using one model run. Table 3-3 lists the CVP M&I contractors included in each region.

Table 3-3. CVP Water Contractors included in OMWEM by Region

Sacramento Valley	San Joaquin Valley
El Dorado Irrigation District	All other Friant-Kern M&I contractors (Arvin-Edison Water Storage District, Delano-Earlimart Irrigation District, Lindsay-Strathmore Irrigation District)
City of Folsom	City of Avenal
Placer County Water Agency	City of Coalinga
City of Redding	City of Fresno
City of Roseville	City of Huron
Sacramento County Water Agency	City of Lindsay
San Juan Water District	City of Orange Cove
City of Shasta Lake, Shasta County Water Agency, Centerville CSD (CSD), Mountain Gate CSD, and Shasta CSD	Stockton-East Water District
City of West Sacramento	City of Tracy

As noted above, the San Francisco Bay Area CVP contractors, EBMUD, CCWD, SCVWD, and SBCWD, are not included in the CAS OMWEM model as they are modeled in the LCPSIM.

3.2.2.1 OMWEM Contractor Demand

Table 3-4 below displays the year 2030 CVP M&I contract quantities and demands for each contractor modeled in OMWEM for the CAS. As noted about with LCPSIM, there are a few important points to consider in regard to the assumed 2030 demand levels used for this study:

- 2030 demands sourced from CVP M&I contractor's 2010 Urban Water Management Plan (UWMP), if available
- 2030 demands sourced from the Bureau of Reclamation's Central Valley Project M&I Water Shortage Policy Draft Environmental Impact Statement (2014), if UWMP is not available
- The 2030 demands published in the UWMPs are assumed to be compliant with the "20% by 2020" legislation, which refers to conservation criteria
- When an UWMP accounts for additional conservation as part of 2030 supply, this is reflected in OMWEM as a demand reduction instead of as new supply

Table 3-4. OMWEM Modeled Demands in 2030

CVP M&I Contractor	2030 CVP Contract Quantities (AF)	2030 Demands from UWMP (AF)
All other Friant-Kern M&I contractors (Arvin-Edison Water Storage District, Delano-Earlimart Irrigation District, Lindsay-Strathmore Irrigation District)	2,926	6,000
City of Avenal	3,500	3,500
City of Coalinga	10,000	10,000
El Dorado Irrigation District	7,550	57,039
City of Folsom	34,000	36,259
City of Fresno	60,000	201,100
City of Huron	3,000	3,000
City of Lindsay	2,500	2,689
City of Orange Cove	1,400	2,790
Placer County Water Agency	100,000	156,333
City of Redding	27,140	27,852
City of Roseville	62,000	49,334
Sacramento County Water Agency	81,438	77,535
San Juan Water District	82,200	57,265
City of Shasta Lake, Shasta County Water Agency, Centerville CSD, Mountain Gate CSD, Shasta CSD	10,672	10,942
Stockton-East Water District	75,000	64,960
City of Tracy	20,000	31,000
City of West Sacramento	23,600	19,273

3.2.2.2 OMWEM Contractor Supply

Table 3-5 below displays the CVP M&I contractor non-CVP supplies for a below normal or better water year and a dry or critical water year. There are some important points to consider in regard to the assumed non-project supplies used for this study:

- Local supplies expected to be available in the year 2030 are based on information from the UWPMs
- OMWEM uses the 2030 "normal" year supplies reported in the UWMPs to represent the 2030 supplies in wet, above normal, and below normal water year types
- OMWEM uses the "multiple-year drought" supplies reported in the UWMPs to represent the 2030 supplies in dry and critical water year types

Table 3-5. OMWEM Assumed 2030 Non-CVP Supplies

CVP M&I Contractor	Non-CVP 2030 Supplies in Below Normal or Better Water Year Type (AF)	Non-CVP 2030 Supplies in Dry or Critical Water Year Type (AF)
All other Friant-Kern M&I contractors (Arvin-Edison Water Storage District, Delano-Earlimart Irrigation District, Lindsay-Strathmore Irrigation District)	3,000	0
City of Avenal	0	0
City of Coalinga	0	0
El Dorado Irrigation District	54,789	54,789
City of Folsom	3,250	11,250
City of Fresno	228,800	232,400
City of Huron	0	0
City of Lindsay	1,210	1,210
City of Orange Cove	0	0
Placer County Water Agency	68,119	103,119
City of Redding	13,424	13,424
City of Roseville	3,397	3,397

CVP M&I Contractor	Non-CVP 2030 Supplies in Below Normal or Better Water Year Type (AF)	Non-CVP 2030 Supplies in Dry or Critical Water Year Type (AF)
Sacramento County Water Agency	74,898	74,898
San Juan Water District	0	0
City of Shasta Lake, Shasta County Water Agency, Centerville CSD, Mountain Gate CSD, Shasta CSD	1,064	1,064
Stockton-East Water District	28,000	50,000
City of Tracy	15,250	16,050
City of West Sacramento	5,000	5,000

3.2.2.3 Summary of OMWEM Logic

The model selects a level of supply that minimizes total cost over the 82-year hydrologic period. For each year and agency, the OMWEM considers demand requirements and CVP supply quantities and attempts to bring about a water balance under average water supply conditions. If new water supplies are necessary, then the model will calculate the amount and costs of additional supplies that would generate the least overall costs by optimizing the mix of shortage and new supply costs, while at the same time accounting for all other costs and savings. This is an iterative process until the total annual cost of water demand and supply management is minimized.

It is important to point out that the OMWEM and LCPSIM are inherently inexact because complex human and organizational decisions surrounding the use of limited resources must be simulated using mathematical descriptions. So although it may not be possible for the economic costs and tradeoffs faced by each CVP M&I contractor to be calculated precisely, the model can provide realistic and representative estimates of economic costs associated with each scenario (with-CVP and without-CVP) and by extension, a representative estimate of the difference in economic costs between the two scenarios. This difference in economic costs represents the benefits (i.e., avoided additional costs of not having the CVP) of the CVP and is the benefit estimate used for the M&I water supply purpose in the SCRB analysis.

Not all CVP M&I water contractors were modeled in OMWEM. If the necessary modeling information required for OMWEM was unavailable or deficient for a particular contractor, then these contractors were not explicitly modeled in OMWEM. To capture the total benefits of the CVP for all non-modeled contractors, average benefits per acre foot were obtained from OMWEM output for the Sacramento and San Joaquin Valleys then multiplied by each contractor's long term historical deliveries. The historical long term average deliveries and benefits by region are shown in Table 7 (in the Results section). The following is a list CVP M&I contractors and conveyance source, if applicable, that are not explicitly modeled in OMWEM:

Sacramento Valley

- Colusa County Water District – Black Butte
- Elk Creek Community Services District
- US Forest Service –Black Butte
- Whitney
- Clear Creek Community Services District
- Bella Vista Water District
- Lake CA Property Owners Association
- Riverview Golf & Country Club
- Colusa County Water District –Tehama Colusa Canal
- Kanawha Water District
- US Forest Service Toyon Pipeline–
- SMUD –Folsom South Canal

San Joaquin Valley

- Fresno County
- Tulare County
- Byron Bethany Irrigation District
- Del Puerto Water District
- Department of Veterans Affairs
- Panoche Water District– Delta Mendota Canal
- San Luis Water District – Delta Mendota Canal
- Madera County Water District
- Fresno County Waterworks #18
- State of California – San Luis Canal
- Westlands Water District – San Luis Canal
- Pacheco Water District – San Luis Canal
- Panoche Water District – San Luis Canal
- San Luis Water District – San Luis Canal

3.3 Results

3.3.1 Non-Modeled Results

Table 3-7 shows the deliveries and benefits for all CVP M&I contractors by region that are not modeled in OWMEM.

Table 3-6. Expected Deliveries and Benefits of CVP M&I Contractors NOT Included in OMWEM (2013 prices)

Category	Sacramento Valley	San Joaquin Valley	Total
Long Term Average CVP M&I Deliveries (TAF)	25	6	31
Average Annual Benefits ($1,000)	$9,046	$3,360	$12,406

3.3.2 LCPSIM and OMWEM Results, Annual Benefits and Present Value of Annual Benefits

Table 3-8 shows the change in CVP M&I deliveries and total expected costs by water year type assumed in each model. The values for change in expected costs are calculated as the total costs of water supply reliability with-CVP in place minus total costs without-CVP in place. As mentioned above, in both the with-CVP and without-CVP scenarios, each CVP M&I contractor's local water supplies and CALSIM II modeled water rights are included in the analysis. Only in the with-CVP scenario are the CALSIM II modeled project water deliveries included. The total expected costs entries in Table 8 represent: 1) all costs to water purveyors as they attempt to meet 2030 water demands and 2) shortage costs faced by water users when actual delivered water does not meet their demands.

Both LCPSIM and OMWEM calculate benefits as the reduction of overall costs by having the CVP in place. To be consistent with other CAS related economics benefit estimates, only the benefit for the water year type "weighted average" is calculated and carry forward for the SCRB analysis. For M&I water supply, it is estimated to be approximately $220 million and is shown in the rightmost column of Table 8; this value is calculated as LCPSIM and OMWEM total water year type weighted average expected costs with-CVP minus weighted average expected costs without-CVP ($207.6 million) plus the total benefits of the CVP contractors not included in OMWEM ($12.4 million from Table 3-7).

Table 3-7: Without-CVP versus With-CVP Expected M&I Water Deliveries and Economic Costs by Water Year Type and Benefits (2013 prices)

Water Year Type	LCPSIM	OMWEM	Total LCPSIM and OMWEM	Benefits[1]
Weighted Average				
CVP M&I Deliveries (TAF)	195	282	477	
Total Expected Costs includes water provision and shortage costs ($1,000)	$82,269	$125,455	$207,587	***$219,994***
Wet				
CVP M&I Deliveries (TAF)	196	333	529	
Total Expected Costs includes water provision and shortage costs ($1,000)	$88,351	$124,872	$213,223	
Above Normal				
CVP M&I Deliveries (TAF)	188	301	489	
Total Expected Costs includes water provision and shortage costs ($1,000)	$85,581	$115,613	$201,194	
Below Normal				
CVP M&I Deliveries (TAF)	184	288	472	
Total Expected Costs includes water provision and shortage costs ($1,000)	$79,800	$110,801	$190,601	
Dry				
CVP M&I Deliveries (TAF)	197	253	450	
Total Expected Costs includes water provision and shortage costs ($1,000)	$77,603	$145,535	$223,138	
Critical				
CVP M&I Deliveries (TAF)	208	190	398	

Water Year Type	LCPSIM	OMWEM	Total LCPSIM and OMWEM	Benefits[1]
Total Expected Costs includes water provision and shortage costs ($1,000)	$75,660	$123,277	$198,937	

1. Includes total benefits from LCPSIM, OMWEM and non-modeled OMWEM contractors

The overall water year type weighted average value of $220 million is used to calculate the present value of future CVP M&I benefits. The present value formula is:

$$PV = \frac{Benefits\left((1-(1+i)^{-n})\right)}{i}$$

PV = present value
Benefits = annual benefits (constant over the project life)
i = discount rate
n = number of years (project life)

For CAS, it is assumed the project life is 100 years and the discount rate is 3.25 percent. Table 3-9 shows the present value of CVP M&I benefits to be approximately $6.5 billion in 2013 prices.

Table 3-8. Total Present Value of CVP M&I Benefits (100 Year Project Life, 3.25% interest rate, 2013 prices)

Total Annual CVP M&I Benefits	$219,994,319
Present Value of CVP M&I Benefits	$6,492,666,135

3.4 Summary of M&I Water Supply Benefits

The present value of CVP M&I benefits estimated for the San Francisco Bay Area (from LCPSIM) and the Central Valley (from OMWEM) are approximately $6.5 billion. This value will be added to the CVP irrigation water supply benefits to calculate the total benefits for all CVP related water supply purposes. The total value of all CVP water supply related benefits will be compared to the single-purpose alternative (SPA) cost estimate for water supply, the lower of the two estimates (benefits or SPA costs) will be the justifiable expenditure for water supply in the SCRB analysis.

Chapter 4. Water Quality

4.1 Introduction & Overview

Water quality is an authorized purpose of the Central Valley Project (CVP). The CVP maintains increased flows in the Trinity, American, and Stanislaus rivers to improve the fisheries habitat and water quality conditions in the San Francisco Bay/Sacramento-San Joaquin Delta and Estuary (Delta). The California State Water Resources Control Board (SWRCB) is responsible for setting water quality standards in the Delta, which govern the operations of both the CVP and the State Water Project (SWP). Specifically, the CVP is responsible for meeting its share of the salinity outflow standards set by the SWRCB, including Water Rights Decision 1485 (D-1485) and Decision 1641 (D-1641). Compliance with D-1485 water quality standards is considered mitigation and not a water quality benefit of the CVP; the cost of complying with D-1485 will be reimbursed in accordance with existing Reclamation law and policy. Conversely, compliance with D-1641 (above D-1485 requirements) is considered a water quality benefit of the CVP and the associated costs are non-reimbursable.

4.2 Methodology

The economic benefits attributed to water quality can be estimated by various methods. For the CAS, water quality benefits are based on the foregone value of the next best use of the water used to meet water quality standards (i.e., irrigation). In other words, CVP water quality benefits are based on the irrigation value of water, which is estimated using the SWAP model. Refer to Chapter 2 (Irrigation Benefits) for more information on the SWAP model and underlying methodology used to estimate the value of irrigation water supplies.

4.2.1 Hydrology Inputs

As noted above, the water quality benefits of the CVP are based on the incremental flow requirements required to meet D-1641 water quality standards (above D-1485); these incremental flows have been measured using CalSim hydrology modeling. CVP water supplies that are used to support water quality benefits are derived from two sources – foregone water deliveries and Delta outflows. Foregone water deliveries consist of irrigation, M&I, and refuge deliveries, and Delta outflows represent water that is retained in stream and ultimately flow out of the system. Foregone irrigation water deliveries are estimated to be approximately 107 TAF annually on average (i.e., across all water year types), while foregone M&I and refuge deliveries are estimated to total about 5 TAF annually. For Delta outflows, approximately 156 TAF of water is required from the combined CVP/SWP system on average; however, only the CVP contribution to Delta outflow requirements is accounted for in the CAS, which is estimated to be about 60 TAF based on COA operating rules. Table 4-1 presents a summary of water requirements to meet incremental D-1641 water quality standards by source and water year type.

Table 4-1. D-1641 Water Requirements, by Source and Water Year Type (TAF)

Water Year Type	Foregone Irrigation Water	Foregone M&I & Refuge Water	Delta Outflows [1,2]	Total
Wet	34.1	1.9	0.0	**36.0**
Above Normal	114.1	5.0	0.0	**119.1**
Below Normal	166.9	6.6	206.0	**379.5**
Dry	117.5	4.2	338.3	**460.0**
Critical	171.1	9.7	449.0	**629.8**
Average	106.8	4.8	60.4	**171.9**

1. Represents CVP portion of Delta outflow requirement

2. CalSim modeling show that (D1641 – D1485) changes to estimated Delta outflow requirements in wet and above normal years are negative; these values have been adjusted to zero.

There are adjustments to the Delta outflow data by water year type that must be accounted for in the modeling of water quality benefits. Delta outflow requirements for the CVP in wet and above normal years are lower under D-1641 relative to D-1485 based on CalSim modeling, suggesting there are no water quality benefits attributed to Delta outflows in those water year types. Therefore, it is not appropriate to include (model) Delta outflows in wet and above-normal water years in SWAP. i.e., Delta outflows were set to zero in wet and above normal water years. Delta outflows were only considered in below normal, dry, and critical water years.

The fundamental premise of the water quality benefit analysis is that all CVP water that is required meet incremental D-1641 requirements must be valued, including foregone irrigation and M&I/refuge deliveries and Delta outflows. As shown in Table 1, this quantity ranges from a low of 36 TAF in wet years to nearly 630 TAF in critical years, averaging 172 TAF across all water years.

4.2.2 Application of SWAP Model

Water quality benefits are quantified based on the value of the water in its next most likely alternative use; in this case, agricultural production using the SWAP model. The steps used in the application of the SWAP model to estimate water quality benefits is presented below:

1. Quantify all CVP water requirements that support water quality benefits (see Table 1).
2. Run the SWAP model simulating the change between the D-1641 and D-1485 hydrology scenarios from CalSim.
3. Distribute the estimated water supplies that support water quality benefits (Step 1) across SWAP regions based on the distribution of changes in irrigation supplies across SWAP regions in the model run in Step 2.

4. Add the calculated CVP water quality requirements (AF) by SWAP region to the existing base-case SWAP model run depicting current conditions (note that this is the SWAP model depicting the with-CVP scenario in the irrigation benefits analysis).
5. Run the SWAP model evaluating the change between the base-case (with-CVP) hydrology and the water quality-adjusted hydrology.
6. Estimate the water quality benefits as the difference in irrigation benefits in the two modeling scenarios in Step 5.

4.2.3 Other Methodological Considerations

The methodology outlined above focuses on the hydrology associated with water quality and the SWAP model; however, there are other important methodological considerations in the estimation of CVP water quality benefits, which are described below.

4.2.3.1 Prospective Period of Analysis – Assumptions

Water quality benefits are based future conditions expected over the 100-year period of analysis. For this study, estimated water quality benefits (reported as an annual value) are assumed to remain constant over the entire period of analysis. The 100-year stream of benefits is discounted over the 100-year period of analysis using a 3.25 percent interest rate for use in the SCRB cost allocation process. It is acknowledged that water quality conditions are dynamic and will change over the 100-year period of analysis; however, due to modeling and data limitations, a single year scenario was used to reflect the prospective period of analysis.

4.3 Water Quality Benefits Results

This section presents estimated water quality benefits provided the CVP. As explained in the methodology section, the water quality benefits are based SWAP modeling, which provides a proxy value for water quality benefits using agricultural values. The benefits reported by SWAP are calculated based on changes in net farm income (profit or producer surplus), surface water and groundwater costs, and land fallowing costs. All monetary values are reported in 2013 dollars.

4.3.1 Summary of Water Quality Benefits

Table 4-2 displays estimated water quality benefits attributed to the CVP. Water quality benefits are estimated to be $49.4 million annually, on average. The greatest benefits occur in critical years ($103.3 million annually) based on the relatively large quantity of CVP water that is needed to meet incremental D-1641 water quality standards. Conversely, the lowest benefits occur in wet years ($7.0 million annually).

Table 4-2. NED Economic Benefits of CVP Water Quality, by Water Year Type ($)

Benefit	Wet	Above Normal	Below Normal	Dry	Critical	Weighted Average
Water Quality	$7,043,111	$21,357,148	$60,744,532	$80,594,730	$103,332,263	$49,387,199

For the CAS, annual water quality benefits are discounted over the 100-year period of analysis using a 3.25 percent interest rate. The present value of CVP water quality benefits is $1,457,558,518.

Chapter 5. Flood Control

5.1 Introduction

The Central Valley Project (CVP) is composed of several dams/reservoirs that were authorized and constructed to meet multiple purposes, one being flood control. The CVP dams/reservoirs that provide flood control benefits include:

- Shasta Dam & Reservoir (Shasta County)
- Folsom Dam & Reservoir (Sacramento County)
- New Melones Dam & Reservoir (Calaveras County)
- Friant Dam & Reservoir (Fresno County)

There are several other CVP facilities that provide flood control benefits, which have not been quantified for the CAS. These facilities include Trinity Dam & Reservoir, Los Banos Creek Detention Dam, and Whiskeytown Dam & Reservoir. Although these facilities provide flood control benefits, they have not been quantified due to lack of available data. As such, the benefits provided in this paper represent a lower bound of flood control benefits provided by the CVP. Further, the omission of flood control benefits at these facilities does not affect the cost allocation because the flood control SPA (and not benefits) represents the justifiable expenditure for flood control in the SCRB calculations.

The following sections summarize the methodology, data, assumptions, and analysis used to estimate the flood control benefits provided by the dams/reservoirs. Benefit estimates for use in the SCRB analysis for the CVP Cost Allocation Study (CAS) are summarized in Table 3 of this report.

5.2 Methodology

Damages Prevented. Flood control benefit estimates were made for each of the first four dams/reservoirs using historical annual damages prevented information provided by the U.S. Army Corps of Engineers (USACE), Sacramento District. The damages prevented reports represent preliminary estimates, by dam/reservoir, using data available at the end of each fiscal year. Because the Corps is responsible for all federal flood control storage, the report includes damages prevented by Corps-operated projects as well as non-Corps projects that have federal flood control storage.

The USACE (Sacramento District) calculates annual damages prevented by comparing downstream river stages at selected sites under regulated flow conditions and unregulated flow conditions. The river stages under each condition are then compared to a stage-damage curve, which describes the amount of damages that could be expected based on a range of river stages representing high exceedance probability to low exceedance probability flow events. The lower amount of damages under the with-project condition as compared to the without project condition reflect the positive effects of reservoir operations on downstream flows and are considered to be the damages prevented (benefits). This computational exercise is performed annually for each dam/reservoir facility having a flood damage reduction purpose.

The USACE damages prevented information was used to estimate benefits for the Shasta Dam & Reservoir, the Folsom Dam & Reservoir, the New Melones Dam & Reservoir, and the Friant Dam & Reservoir. The damages prevented information was updated to October 2013 price levels, and total benefits were computed over a 100-year period of analysis using a discount rate of 3.25%. The damages prevented information for each dam/reservoir is presented in Table 1 below.

5.3 Data

Damages Prevented. The USACE provided damages prevented data up to the year 2010. Table 5-1 below displays the information by dam/reservoir. Adjustment factors for each year of record were calculated using 2013 as the base year and the Gross Domestic Product (GDP) Implicit Price Deflator. These factors, which are displayed in the table, were applied to the historical nominal values to convert annual damages prevented to 2013 prices.

The information from the Corps of Engineers indicate that over the historical period of record, Shasta Dam & Reservoir, Folsom Dam & Reservoir, New Melones Dam & Reservoir, and Friant Dam & Reservoir have prevented approximately $29 billion, $33 billion, $525 million, and $525 million in damages, respectively. A total of approximately $63 billion in damages have been prevented by these dams/reservoirs combined.

Table 5-9. Annual Flood Damages Prevented by Dam/Reservoir ($1,000s) – Nominal and 2013 Price Level

Year	Shasta (Nominal)	Folsom (Nominal)	New Melones (Nominal)	Friant (Nominal)	Value Index Adjustment	Shasta (2013 Price Level)	Folsom (2013 Price Level)	New Melones (2013 Price Level)	Friant (2013 Price Level)
1952	0	--	--	--	7.122	0	--	--	--
1953	0	--	--	--	7.035	0	--	--	--
1954	0	--	--	--	6.970	0	--	--	--
1955	105,000	--	--	--	6.853	719,614	--	--	--
1956	0	--	--	--	6.627	0	--	--	--
1957	1,000	--	--	--	6.414	6,414	--	--	--
1958	100,000	--	--	--	6.272	627,246	--	--	--
1959	100,000	--	--	--	6.186	618,602	--	--	--

Year	Shasta (Nominal)	Folsom (Nominal)	New Melones (Nominal)	Friant (Nominal)	Value Index Adjustment	Shasta (2013 Price Level)	Folsom (2013 Price Level)	New Melones (2013 Price Level)	Friant (2013 Price Level)
1960	0	--	--	--	6.101	0	--	--	--
1961	194,000	--	--	--	6.035	1,170,823	--	--	--
1962	0	--	--	--	5.962	0	--	--	--
1963	200,000	--	--	--	5.895	1,179,049	--	--	--
1964	0	--	--	--	5.806	0	--	--	--
1965	150,000	--	--	--	5.702	855,303	--	--	--
1966	0	--	--	--	5.546	0	--	--	--
1967	10,000	--	--	--	5.390	53,895	--	--	--
1968	0	110	--	--	5.170	0	569	--	--
1969	12,000	0	--	--	4.927	59,123	0	--	--
1970	100,000	6	--	--	4.680	468,007	28	--	--
1971	0	0	--	--	4.454	0	0	--	--
1972	0	0	--	--	4.269	0	0	--	--
1973	0	0	--	--	4.048	0	0	--	--
1974	80,000	0	--	--	3.714	297,104	0	--	--
1975	0	0	--	--	3.400	0	0	--	--
1976	0	0	--	--	3.223	0	0	--	--
1977	0	0	--	--	3.035	0	0	--	--
1978	55,000	0	2	--	2.837	156,012	0	6	--
1979	0	0	0	--	2.619	0	0	0	--
1980	120,000	5	298	--	2.402	288,286	12	716	--
1981	0	0	0	--	2.197	0	0	0	--
1982	130,000	7	13,000	--	2.069	268,966	14	26,897	--
1983	2,801,000	900	12,700	23,690	1.991	5,576,216	1,792	25,283	47,162
1984	40,000	0	0	0	1.922	76,896	0	0	0

Year	Shasta (Nominal)	Folsom (Nominal)	New Melones (Nominal)	Friant (Nominal)	Value Index Adjustment	Shasta (2013 Price Level)	Folsom (2013 Price Level)	New Melones (2013 Price Level)	Friant (2013 Price Level)
1985	0	0	0	0	1.863	0	0	0	0
1986	3,116,000	6,488,100	102,500	33,190	1.826	5,689,243	11,846,078	187,146	60,599
1987	0	0	0	0	1.781	0	0	0	0
1988	0	0	0	0	1.720	0	0	0	0
1989	0	0	0	0	1.656	0	0	0	0
1990	0	0	0	0	1.597	0	0	0	0
1991	0	0	0	0	1.545	0	0	0	0
1992	0	0	0	0	1.511	0	0	0	0
1993	0	0	0	0	1.476	0	0	0	0
1994	0	0	0	0	1.445	0	0	0	0
1995	3,499,000	5,700	2,100	54,310	1.415	4,952,651	8,068	2,972	76,873
1996	0	0	2,400	0	1.390	0	0	3,336	0
1997	4,267,000	15,194,472	175,770	3,320	1.367	5,831,689	20,766,215	240,224	4,537
1998	12,229	900	8,030	28,630	1.352	16,534	1,217	10,857	38,709
1999	0	3,190	2,670	15,390	1.333	0	4,252	3,559	20,515
2000	8,350	0	470	36,200	1.303	10,883	0	613	47,182
2001	0	0	0	11,750	1.274	0	0	0	14,971
2002	6,690	0	0	4,420	1.255	8,395	0	0	5,546
2003	13,140	0	0	21,270	1.230	16,167	0	0	26,170
2004	28,610	0	0	4,470	1.198	34,261	0	0	5,353
2005	0	0	1,750	64,440	1.160	0	0	2,031	74,769
2006	11,550	90,910	18,740	72,530	1.126	13,001	102,332	21,095	81,643
2007	0	0	0	0	1.097	0	0	0	0
2008	0	0	0	0	1.075	0	0	0	0
2009	1,818	0	370	9,678	1.067	1,940	0	395	10,329

Year	Shasta (Nominal)	Folsom (Nominal)	New Melones (Nominal)	Friant (Nominal)	Value Index Adjustment	Shasta (2013 Price Level)	Folsom (2013 Price Level)	New Melones (2013 Price Level)	Friant (2013 Price Level)
2010	0	0	0	10,284	1.055	0	0	0	10,845
Total	**15,162,387**	**21,784,300**	**340,800**	**393,572**	**--**	**28,996,323**	**32,730,577**	**525,129**	**525,203**

5.4 Summary of Flood Control Benefits

Damages Prevented. The damages prevented totals from Table 5-1 were divided by the number of years of record, per dam/reservoir, to derive an average annual damages prevented value. For example, the total damages prevented for Shasta Dam & Reservoir over the entire period of record for that reservoir (1952 to 2010) is approximately $29.0 billion (2013 dollars). This value was then divided by 59 (the number of years in the period of record for Shasta Dam) to derive an average annual flood damages prevented value of approximately $491.5 million; note that the period of record for each dam/reservoir varies. Table 5-2 displays the average annual damages prevented values for each dam/reservoir.

Table 5-10. Average Annual Damages Prevented by Dam/Reservoir (2013 dollars)

Shasta Dam & Reservoir	Folsom Dam & Reservoir	New Melones Dam & Reservoir	Friant Dam & Reservoir
$491,463,000	$761,176,000	$15,913,000	$18,757,000

Average annual damages prevented for each dam/reservoir were then used to calculate the present value of future benefits over the 100-year period of analysis using a discount rate of 3.25%. The present value formula is:

$$PV = \frac{PMT\left((1-(1+i)^{-n})\right)}{i}$$

PV = present value
PMT = payment (benefits) per period
i = discount rate
n = number of payment periods

The present value of a future stream of payments (benefits) for each dam/reservoir was calculated using the average annual damages prevented values displayed in Table 5-2. Table 5-3 shows the total benefits for each dam/reservoir. Using the USACE damages prevented information, total flood control benefits over the 100-year period of analysis for all facilities are estimated to be approximately $38.0 billion.

Table 5-11. Total Benefits[1] over 100-Year Period of Analysis (2013 dollars)

Shasta Dam & Reservoir	Folsom Dam & Reservoir	New Melones Dam & Reservoir	Friant Dam & Reservoir	Total
$14,504,492,000	$22,464,503,000	$469,638,000	$553,581,000	$37,992,214,000

1. 100-Year Period of Analysis, using 3.25% Discount Rate

Chapter 6. Hydropower

This chapter describes the methodology used to estimate economic benefits attributed to CVP hydropower generation and results of the analysis. The estimation of hydropower benefits was coordinated with the Western Area Power Administration (WAPA) and CVP energy generation was estimated using output from CalSim 2 and LTGEN models (see *Hydrological Modeling Appendix* for more details). Attachment 1 (*Economic Benefits Analytical Tool Descriptions) and* Attachment 2 (*Forecast of Economic Value of CVP Power 2014-2113*) to this *Economic Benefits Analysis Appendix* describe the PLEXOS model and application of the model to estimate CVP hydropower benefits, respectively. Background, methodology, and results are described below.

6.1 Background

CVP hydropower benefits were estimated for energy, ancillary services, and planning capacity/resource adequacy components, generally described below:

6.1.1 Energy

The California Energy Commission (CEC) defines energy as "the capacity for doing work." Forms of energy include thermal, mechanical, electrical, and chemical. For hydropower, energy is in the form of electrical generation that is produced when water runs through the hydro-electric turbines. Traditionally, hydropower plant operators have strived to maximize on-peak generation, (i.e., generation provided during the peak load hours as defined by the North American Energy Standards Board (NAESB)). In the case of CVP, since hydropower is generated only when reservoir releases are made to meet higher priority purposes as flood control, water supply, and environmental regulatory needs, hydropower is not optimized for its maximal value of electricity generation, but only suboptimal for electricity generation within the context of the daily water release schedule. This study, therefore, estimated the value of CVP hydropower generation subject to given constraints due to hydrology, project consumption, and regulatory operations or COA requirements which may change the timing, value, and quantity of CVP hydropower available for sale. The results of the study are estimates because the constraints used by the model are a simplified representation of the complex reality of operational and regulatory requirements.

The study is based on the contemporary fact that the value of CVP generation is realized through the local organized electricity market operated by the CAISO. The value of the CVP generation to a wholesale CVP customer is assessed and realized by the CAISO wholesale electricity market price. The CAISO market prices are determined by locational marginal prices. A locational marginal price is usually the highest bid price accepted by the market at a given location. A wholesale electricity consumer can simply go to the CAISO wholesale electricity market to purchase the electricity if the CVP generation is priced higher than the CAISO locational marginal prices. Therefore, the study evaluates CVP generation values using the locational marginal prices simulated by the PLEXOS model. In calculating the locational marginal prices, it was determined that since the CVP hydropower generation represented a very small amount of the total generation output available to the California market, it was decided that a with-and without-CVP analysis was not necessary. As a result, the value of CVP hydropower was estimated using the simulated CAISO's hourly day-ahead price (i.e., market prices) as a proxy to represent the marginal value of the hydropower generation. This is the streamlined approach referenced later in Section 6.2 of this appendix.

The calculated locational marginal prices are based on assumptions of certain resource mixes that represent a snapshot in time, for example the 33 percent renewable portfolio standard (RPS). In recent years as the amount of renewable generation from wind and solar resources have increased from the imposition of the mandatory RPS, it has resulted in the creation of surplus capacity and generation during certain hours of the day, and consequently resulted in the displacement of generation from traditional sources such as natural gas, nuclear, and hydropower. Simultaneously, energy demands have leveled and increased at lower rates as a result of increased energy use efficiencies, distributed generation resources and lower than expected population growth rates.

As the renewable generation from wind and solar resources has increased, there may be more value in the future energy and ancillary markets if CVP generation can be dispatched to fully utilize the fast-ramping capability of a hydro generator. The value of such benefits, however, are not sufficiently realized now and may be constrained by water operations, environmental regulations, contractual constraints/limitations, and the governing Power Marketing Plan.

6.1.2 Ancillary Services

The CEC defines ancillary services as "services other than scheduled energy that are required to maintain system reliability and meet Western Electricity Coordinating Council/North American Electric Reliability Corporation operating criteria. Such services include spinning, non-spinning, and replacement reserves, voltage control, and black start capability." Hydropower can be particularly valuable at providing regulation-up and regulation-down ancillary services because hydro generation can be ramped up (regulation-up) or down (regulation-down) quickly to allow the grid operator to precisely match generation to load, especially when wind and solar generation fluctuates unexpectedly. When ancillary services are bid into the market, it is common that they are not called upon. A generating entity is paid for providing ancillary service capacity into the market and then paid for the energy, if generation is actually called upon in connection with the bid.

6.1.3 Planning Capacity/Resource Adequacy

The CEC defines capacity as "the amount of electric power for which a generating unit, generating station, or other electrical apparatus is rated either by the user or manufacturer." Capacity is valuable because of the need for sufficient machine capability to meet the peak electrical load hour during the hottest summer day. Flexible capacity is becoming more valuable as California continues to increase the proportion of renewable energy (other than large hydro) required to meet total energy demanded. Because renewables have resulted in creating a significant amount of excess capacity in California, estimating a value for capacity, especially where the CAISO does not run a capacity market can be problematic. Resource Adequacy (RA) is a mandatory planning and procurement process to ensure resources are secured by Load Serving Entities to meet CAISO's forecast system, local, and flexible capacity needs.

6.2 Methodology

The power benefit analysis for the CAS is based on a streamlined approach to estimate benefits of CVP hydropower based on simulated market prices. A proof-of-concept test was implemented to validate a streamlined approach, which confirmed the hypothesis that electricity market prices with- and without-CVP conditions are not significantly different, thus allowing a market-price approach. The annual value of energy, ancillary services, and planning capacity/resource adequacy hydropower benefits evaluated for the CAS was composed of as follows:

- **Energy –** Forecasted California Independent System Operator (CAISO) hourly day-ahead market prices for energy from PLEXOS model (see Attachment 1 - *Economic Benefits Analytical Tool Descriptions*, for description of PLEXOS model),

- **Ancillary Services –** Forecasted CAISO hourly day-ahead market prices for ancillary services from PLEXOS model, and

- **Planning Capacity/Resource Adequacy –** Claimed RA by CVP Preference Power Customers to meet demand/load growth considerations by applying CAISO market prices.

The PLEXOS Integrated Energy Model (PLEXOS) is a power market simulation model used to evaluate CVP power accomplishments and benefits. The PLEXOS Model (described in Attachment 1 – *Economic Benefits Analytical Tool Descriptions*) was used to estimate energy and ancillary service benefits (see Attachment 2 – *Forecast of Economic Value of CVP Power 2014-2113*), while planning capacity/resource adequacy was estimated as the avoided cost of RA that is currently claimed by some CVP preference power customers.

The PLEXOS model was selected for use in the CVP CAS based on a variety of factors including (but not limited to) its relative ability to accurately simulate different future scenarios given specific constraints, as well as its widespread usage in the power industry. PLEXOS simulates power markets by optimizing energy, ancillary services, generation, and transmission utilization subject to physical and operational constraints. Two simulations were run to determine CVP power benefits. The first covered the entire Western Electricity Coordinating Council's (WECC) system to generate projected pricing and ancillary services data, including CVP facilities. A subsequent simulation optimized the dispatch of the CVP facilities using the projected pricing and ancillary services data generated in the first simulation. The simulated generation data is a 2024 baseline year used to calculate annual benefits across the period of analysis used in the study. See Attachment 2 – *Forecast of Economic Value of CVP Power 2014-2113* for more detailed documentation of the analysis used to estimate energy and ancillary services.

The energy component of CVP hydropower benefits was adjusted in relation to two factors discussed below: 1) estimated generator flood bypass, and 2) San Luis Unit pump-generating unit. In addition, valuation of planning capacity/resource adequacy is described below.

6.2.1 Energy Benefit Adjustment for Estimated Generator Flood Bypass

The LTGEN model estimates monthly generation at a given hydropower facility based on generation capacity, monthly storage, and total monthly release[1]. Output from LTGEN (i.e., total monthly generation) and facility data (i.e., minimum and maximum generation) were inputted to PLEXOS to develop constraints during the second PLEXOS simulation to estimate power benefits given the estimated locational market prices in the first simulation. After the PLEXOS CVP benefit simulation was completed, it was determined that the version of the LTGEN model used to develop inputs to the PLEXOS model overestimated generation when compared to the historical generation levels due to underestimation of generator flood bypasses. This overestimation was identified based on a separate analysis where the LTGEN modeled generation developed with historical water record inputs exceeded the actual historical generation due to missed (underestimated) flood bypass. Because monthly generator constraints were estimated using the version of LTGEN subject to underestimation of generator flood bypass and input into PLEXOS, the simulated 2024 baseline year utilizes overestimated generation leading to inflated power benefits.

A post-production methodology was developed to isolate the missed flood bypass from LTGEN to adjust the power benefits estimated by PLEXOS. This post-process adjustment of LTGEN and PLEXOS results was performed for the energy component of the power benefits in the CAS. The methodology consisted of isolating flood bypass using hourly data (acquired from Reclamation's Central Valley Operations Office) of operations at Trinity, Folsom, Shasta, Keswick, and Nimbus reservoirs[2]. These are the main CVP facilities which experience flood bypass operations and thus contributed to the over-calculation in LTGEN. A comparison was made between the total bypass and the amount of remaining available capacity at each facility on an hourly timestep to generate an hourly time-series of flood bypass. This newly generated time-series data was aggregated to a monthly time-step for compatibility with the LTGEN model. This data was then subtracted from the LTGEN predicted spill and multiplied by the monthly efficiency factor to produce a prediction of overestimated generation due to missed flood bypass.

Logarithmic regression analyses were then developed to map the historical data to the respective CalSim 2 data. Estimated generation from LTGEN was regressed on the Sacramento Valley Hydrological Classification Index[3] for the adjusted and unadjusted numbers. The difference in the regression lines was summarized by water year type to estimate the average percentage CVP generation overestimated due to missed flood bypass by water year type. The result of this analysis provides the adjustment factor applied to estimated generation by water year type, which is reported in Table 6-1.

[1] See the Hydropower Purpose section of the *Hydrological Modeling Appendix* for more information about the LTGEN model.

[2] In coordination with the Central Valley Operations Office, historical data from 2009 – 2017 water years were chosen due to consistency with historical and simulated operations, constraints on the availability of hourly data, and variability in water year types over the time period.

[3] The Sacramento Valley Hydrological Classification Index (Sac Index) is computed annually by the California Department of Water Resources to determine the water year type. The regression used the computed index value for each water year incorporated into the analysis. Sac index values are publicly available on DWR's website.

Table 6-1. Percent Reduction of Energy Component of Power Benefit Energy Results by Water Year Type

	Wet	Above Normal	Below Normal	Dry	Critical
Percent Reduction for Energy Generation Benefits	3.74%	3.27%	2.71%	2.37%	0.74%

Table 2 of Attachment 2 displays the 2024 simulated energy sales and associated energy revenue by water year type as estimated by the PLEXOS model. By dividing the total energy revenue by energy sales, average unit prices by water year type were estimated. These unit prices range from $39/MWh in wet years to $43/MWh in critical years. The quantity of energy generation by water year type was then reduced by the respective percentage reported in Table 6-1. This reduction in generation was subsequently multiplied by the respective unit price. The resulting reduction in energy value (revenue) by water year type was weighted by the water year distribution to calculate an annual average reduction in energy value accounting for missed flood bypass. Table 6-2 reports the power benefits after implementation of the adjustment[4].

6.2.2 Energy Benefit Adjustment for the San Luis Unit Pump-Generating Unit

The San Luis Unit is part of both the Federal CVP and the California SWP. Authorized by the San Luis Act in June 1960 (Public Law 86-488), it is jointly operated by Reclamation and the DWR primarily for the purpose of water supply. Two features of the San Luis Unit are pump-generating ("pump-gen") plants – the O'Neill Pump-Generating Plant and the William R. Gianelli Pump-Generating Plant. These two facilities pump water into the O'Neill Forebay and San Luis Reservoir respectively, for off-stream storage. During water operations, water is either released for delivery from O'Neill Forebay into the Delta Mendota Canal or from San Luis Reservoir back through the pump-turbines of both facilities to generate reclaimed energy. The reclaimed energy helps offset part, but not all of the cost of pumping water into San Luis Reservoir. Because the energy required to pump water into the reservoir is greater than the energy generated when the water is released for delivery, all of the energy generated by these pump-gen plants is considered to be an offset to the cost of pumping.

Accordingly, the total cost of both pump-gen plants, as well as the value of the energy generated by them, was assigned to the water supply purpose. As a result, it was necessary to adjust (reduce) the energy power benefits modeled in PLEXOS by the value of generation produced by the pump-gen plants and add that value to the water supply benefits. The relative proportion of generation at the San Luis Unit was calculated by dividing the annual energy generated by the San Luis Unit minus transmission losses by the total annual CVP energy generated minus transmission losses. Specifically, the adjustment factor used to adjust hydropower benefits is calculated by the following equation:

[4] See Table 2 of Attachment 2 *(Forecast of Economic Value of CVP Power 2014-2113)* for the results of the power benefits analysis prior to the application of the adjustment to account for underestimated generator flood bypass.

$$\boldsymbol{Adjustment\ Factor}\ (\%) = \mathbf{1} - \frac{\boldsymbol{Annual\ San\ Luis\ Unit\ Generation - San\ Luis\ Unit\ Transmission\ Losses}}{\boldsymbol{Total\ Annual\ CVP\ Generation - Total\ Transmission\ Losses}}$$

The adjustment factor (0.975) was multiplied by the estimated annual energy generation benefits prior to calculating the discounted net present value over the planning horizon. The adjustment factor did not affect the benefits attributed to ancillary services or RA.

6.2.3 Planning Capacity/Resource Adequacy

Planning capacity/resource adequacy was estimated as the avoided cost of RA that is currently claimed by some CVP preference customers. This is different from the planning capacity benefits described in Attachment 2 (*Forecast of Economic Value of CVP Power 2014-2113*).

Although WAPA only markets two non-firm variable products, energy and ancillary services, some of WAPA's customers claim their CVP allocation for capacity purposes, thus avoiding certain CAISO costs related to short-term operational requirements to ensure grid reliability. These grid reliability requirements are referred to as RA. Using the CAISO market value for RA is considered to be representative of the actual value that WAPA preference power customers are realizing when claiming CVP capacity benefits. A CAISO market-based price for RA was used as a proxy for that value now and for the foreseeable future, since its value is calibrated to the amount of capacity present in the existing and predicted future system.

As referenced in Table 3 of Attachment 2 (*Forecast of Economic Value of CVP Power 2014-2113)*, CVP Preference Customers claim 635 MW of capacity to meet their RA commitment. The 635 MW is dispersed among the Sacramento Municipal Utility District (308 MW), Northern California Power Agency (229 MW), and City of Redding (98 MW). The capacity amounts are directly stated in 2014 California Energy Commission (CEC) filings titled "Electric Resource Planning Form S-1" for each utility, which are publicly available on the CEC website. The values reported for each utility are the peak month capacity claimed in 2014.

The economic value of RA is based on the peak month capacity to account for avoided cost and willingness to pay similar to single purpose alternative facility sizing. For example, if a single purpose power plant to provide RA were built, it would be sized to handle the peak month value so the facility could provide the claimed capacity when needed. For the purposes of this CVP CAS, this capacity is being considered as an avoided cost to be claimed as additional benefits. The value of RA varies due to heterogeneous seasonal demand throughout the year. To model RA, an average price of $2.21/kw-month was determined using WAPA's RA purchases during 2009-2013. The total value for RA is then:

(635,000 kw) x (12 months) x ($2.21/kw-month) = $16.8 million/year

6.3 Results

The estimated energy and ancillary service CVP power benefits are shown in Table 6-2, and estimated total hydropower benefits are shown in Table 6-3. As discussed above, the benefit values used in the CAS for the power purpose are the values of CVP energy generated without the San Luis Unit. The value of energy generated by the O'Neill and Gianelli pump-generating plants was subtracted from the estimated hydropower benefit and added to the estimated water supply benefit. In addition (shown in Table 6-3), the estimated capacity/resource adequacy value ($16.8 million) was added and total hydropower benefits (without San Luis Unit) and benefits are estimated to be nearly $193.9 million annually, on average.

Table 6-2. Estimated Annual CVP Hydropower Energy and Ancillary Benefits, by Water Year Type ($millions)

Power Component	Wet	Above Normal	Below Normal	Dry	Critical	Weighted Average
Energy	$228.1	$201.5	$170.6	$155.1	$115.4	$181.1
Ancillary Services	$0.7	$0.5	$0.4	$0.4	$0.5	$0.5
Total	**$228.7**	**$202.1**	**$171.0**	**$155.5**	**$116.0**	**$181.6**

Table 6-3. Estimated Annual Total CVP Hydropower Benefits ($millions)

Benefit	Amount
CVP Hydropower Energy and Ancillary Service Benefit (with San Luis Unit)	$181.6
Less: San Luis Unit Energy Benefit (Water Supply Cost Saving Benefit)	$4.5
CVP Hydropower Energy and Ancillary Service Benefit	$177.1
Plus: CVP Capacity (Resource Adequacy) Benefit	$16.8
Total Estimated Annual CVP Hydropower Benefit	$193.9

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RECLAMATION
Managing Water in the West

CVP Cost Allocation Study
November 19, 2013

Description of Analytical Tools

Name
State**w**ide **A**gricultural **P**roduction Model (SWAP)

Availability of Technical Support
A summary of SWAP documentation is available on SWAP web site:
http://swap.ucdavis.edu/

Categories
Optimization of crop acreage

Main Features and Capabilities
- *Yearly* time step
- Spatial scale (27 regions comprising the Central Valley of California based on local hydrology and DWR's Detailed Analysis Units (DAU)
- SWAP considers 20 crops
- SWAP projects future cropping patterns, land use, and water use by considering land and water availability and their costs, market conditions, and production costs.
- The model selects those crops, acreage and water supplies that maximize profit subject to certain constraints.
- Constraints include availability of land, labor, water and supplies.
- SWAP uses Positive Mathematical Programming (PMP) technique to incorporate both marginal and average economic conditions when maximizing profit.

Applications
SWAP is an extended and improved version of Central Valley Production Model (CVPM). The older CVPM has already been applied in the past Water Plan Updates to forecast future crop acreage for the of the Central Valley regions. Though the current SWAP has not yet been used to forecast future crop acreage, but it has been tested with past historical data for the purpose of calibration and verification.

Calibration/Validation/Sensitivity Analysis
Calibration refers to the calculation of some model parameters in such a way that the model will predict a given set of target data. The SWAP is calibrated against irrigated acreage by crop and by region.

An innovation in the SWAP model over the CVPM model and related PMP models is the use of exponential cost functions. The exponential form of the cost function has several advantages over the more frequently specified quadratic cost function. The most important practical advantage is that the exponential cost function is better able to fit a desired elasticity of supply without forcing the marginal cost of production of the initial unit to assume unrealistic values.

Peer Review

Although PMP technique has been published in refereed journals, no official Review of SWAP has been conducted.

Anatomy of SWAP

Conceptual Basis

Conceptually, SWAP is an agricultural crop acreage model that simulates the decisions of agricultural producers (farmers) on a regional level based on principles of economic optimization. The model assumes that farmers maximize profit subject to resource, technical, and market constraints. Farmers sell and buy in technical and institutional constraints.

Theoretical Basis

Traditional optimization models such as linear programming rely on data based on observed average conditions (e.g., average production costs, yields, and prices), which are expressed as fixed coefficients. As a result, these models tend to select crops with highest average returns until resources (land, water, and capital) are exhausted. The predicted crop mix is therefore less diverse than observed in reality. The most widespread reason for diversity of crop mix is the underlying diversity in growing conditions and market conditions. Simply put, any crop-producing region includes a broad range of production conditions. All farms and plots of land do not produce under the same, average set of conditions. Therefore, the marginal cost and revenue curves do not coincide with average cost and revenue curves. To account for crop diversity, SWAP has been formulated on the basis of marginal (incremental) conditions.

Numerical Basis

Numerical basis of SWAP is a technique called Positive Mathematical Programming (PMP) which incorporates both marginal and average conditions. In the conventional case of diminishing economic returns, productivity declines as output increases. Therefore, the marginal cost of producing another unit of crop increases as production increases and the marginal cost exceeds the average cost. The PMP technique uses this idea to reproduce the variety of crops observed in the data. Several possible or combined reasons for crop diversity are: diverse growing conditions that cause variation in production costs or yield; crop diversity to manage and reduce risk; and constraints in marketing or processing capacity. SWAP assumes that the diversity of crop mix is caused by factors that can be represented as increasing marginal production cost for each crop at a regional level. For example, SWAP costs per acre increase for cotton farmers as they expand production onto more acreage. The PMP approach used in SWAP uses empirical information on acreage responses and shadow prices—implicit prices of resources—based on standard linear programming techniques and a calibration period data set. The acreage response coefficients and shadow prices are used to calculate parameters of a quadratic cost function that is consistent with economic theory. The calibrated model will then predict exactly the original calibration data set, and can be used to predict impacts of specified policy changes such as changes in water supplies.

Input and Output

Main categories of inputs and outputs in SWAP are as follows. Inputs: (Water supply by source, Crop unit water use (ETAW), Ag water use efficiency, Crop production function, Crop yield, Crop demand information, Crop price, Cost of water, Cost of groundwater pumping (energy cost), groundwater pumping depths and lifts, Farm policy) Outputs**:** (Crop acreage by region, Ag water use by region, Crop revenues, Producers profit, Consumers surplus)

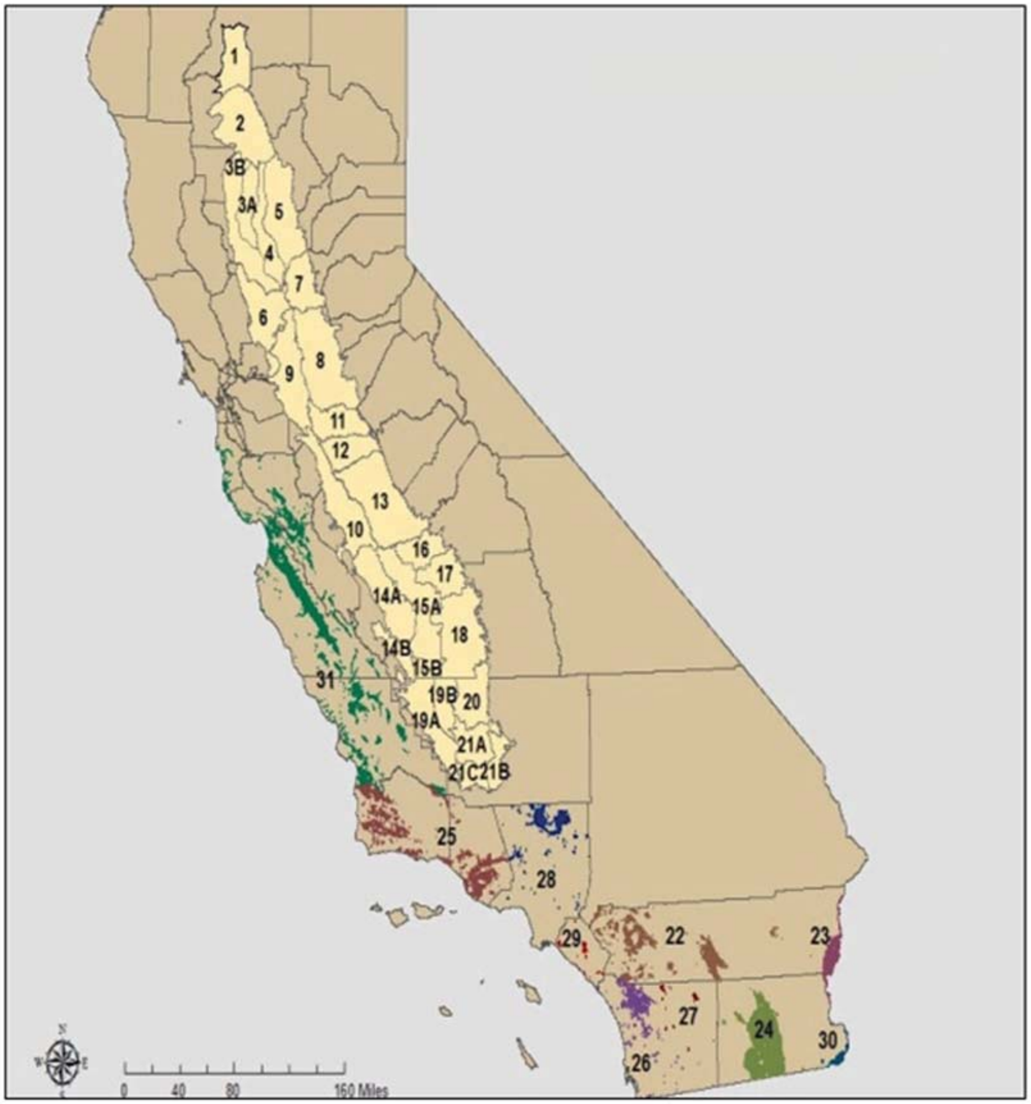
Data Management

All input and output data are stored locally. Some of SWAP input data are based on field and market information (e.g. crop yield, Ag water use efficiency, crop prices, and cost of water). Other inputs come from the result of other models like CALSIM to provide information on amount water supply available for Ag from SWP and CVP projects.

Software

SWAP operates using the General Algebraic Modeling System (GAMS) software. GAMS software is available from GAMS Development Corp., 1217 Potomac Street, N.W., Washington, and D.C 20007, U.S.A. This software is available for Window based personal computers and a variety of workstations or larger computers. The SWAP code is public domain and portable across all of these platforms.

Figure 1. SWAP Coverage of Agriculture in California



20 Proxy Crops used in SWAP Model

- Almonds
- Alfalfa Hay
- Corn
- Cotton, Upland and/or Pima
- Summer Squash/Squash
- Dry Beans
- Fresh Tomatoes
- Wheat
- Onions
- Walnuts

- Sudan Grass, Hay
- Broccoli
- Pasture
- Potato
- Processing Tomatoes
- Rice
- Safflower
- Sugar Beets
- Oranges, Navel and/or Valencia
  Vineyards, Grapes Wine, Table Grapes, Raisin Grapes

RECLAMATION
Managing Water in the West

CVP Cost Allocation Study

November 19, 2013

Description of Analytical Tools

Name

Least-Cost Planning SIMulation model (LCPSIM)

Author

California Department of Water Resources (Ray Hoagland, Division of Planning and Local Assistance)

Categories

Economic optimization, urban water system simulation

Main Features and Capabilities

- Spatial scale at hydrologic region/planning area.
- Simulation runs through a hydrologic sequence of supplies and rainfall-correlated demands at a specified level of future demand (e.g., 2020) on a *yearly* time step.
- *Reliability enhancement options* are adopted based cost minimization ($ per thousand acre-feet) and include long-run demand reduction and supply augmentation measures, such as toilet retrofit and wastewater recycling, to reduce frequency, magnitude, and duration of shortage events.
- Cost of *reliability enhancement* (thousands of $) expressed as a function of the level of adoption of *reliability enhancement options* (thousands of acre-feet).
- S*hortage contingency measures* such as water transfers (based on minimizing cost among transfer options) and shortage allocation by *water use category* in the region/planning area (residential, commercial, industrial, and large landscaping); are used for shortage management.
- *Expected economic losses* (thousands of $) are produced by an *economic loss function* which uses the percentage size of shortage (foregone use) events generated by the simulation as well as the percentage size of each *water use category*.
- *Demand hardening* is computed as a function of the level of use of demand reduction measures and used to adjust *expected economic losses*.
- Cost of unreliability (thousands of $) is expressed as a function of the level of adoption of *reliability enhancement options* (thousands of acre-feet) and includes *expected economic losses* as well as the expected costs of *shortage contingency measures*.

- *Reliability management cost* (thousands of $) includes the cost of *reliability enhancement*, the cost of *unreliability*, and the cost of carryover storage operations, conveyance, treatment, and distribution.
- The *least-cost reliability management plan* is identified by minimizing *reliability management cost* expressed as a function of *reliability enhancement*.
- Operations of *carryover storage facilities* available to the region/planning area (including ground water banking) are used for reliability management in LCPSIM.
- Priority-based objective, mass balance-constrained linear programming is used to operate *carryover storage facilities* and balance (to the extent possible) available supplies with demands on a yearly basis.
- The State Water Project is treated as the residual source of supply: SWP supply quantities available for delivery to the region/planning area which are unusable and unstorable in any year of the simulation are identified.

Applications
The model has been applied to the San Francisco Bay and South Coast hydrologic regions at the 2020 level of demand to determine the regional economic benefit value of additional State Water Project deliveries.

Calibration/Validation/Sensitivity Analysis
Validation of LCPSIM has not been performed due to lack of comparable historical data available for a region to check against model results and the fact that LCPSIM was designed as a normative rather that a positive (predictive) model. Verification is being performed in a peer review process (see below). Sensitivity analysis, which does not require actual historical data, can be performed independently of calibration/validation to test the sensitivity of model results against key input parameters. Limited sensitivity analyses have been part of the peer review process.

Peer Review
Members of the Bay-Delta Authority Common Assumptions Economics Workgroup has been involved in reviewing and suggesting modifications to LCPSIM since mid-July of 2004. This work was completed in 2005.

Anatomy of LCPSIM

Conceptual Basis
Conceptually, the primary objective of LCPSIM is to develop an economically efficient regional water management plan based on the principle of least-cost planning. At the least complex level, LCPSIM evaluates the effect of the availability of additional imported water supplies on the net value of adopting regional long-run water management options such as recycling or toilet retrofit programs and on costs and losses associated with shortage events. At a more complex level, LCPSIM evaluates the availability and use of contingency

strategies to mitigate the economic impacts of shortage events, such as short-term water market transfers, use of supplies from carryover storage (conjunctive use), and water allocation programs. These strategies can affect the economically efficient level of adoption of the long-term water management measures. Conversely, the level of adoption of long-term measures can influence the effectiveness of the contingency management strategies and, therefore, their use.

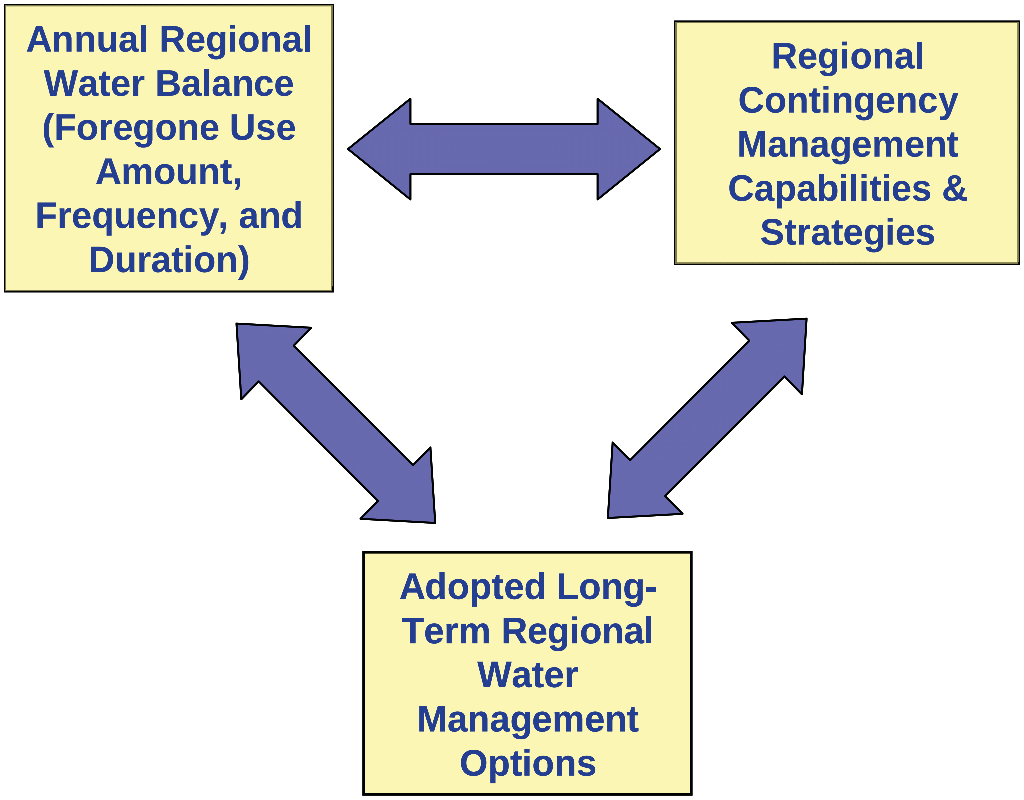


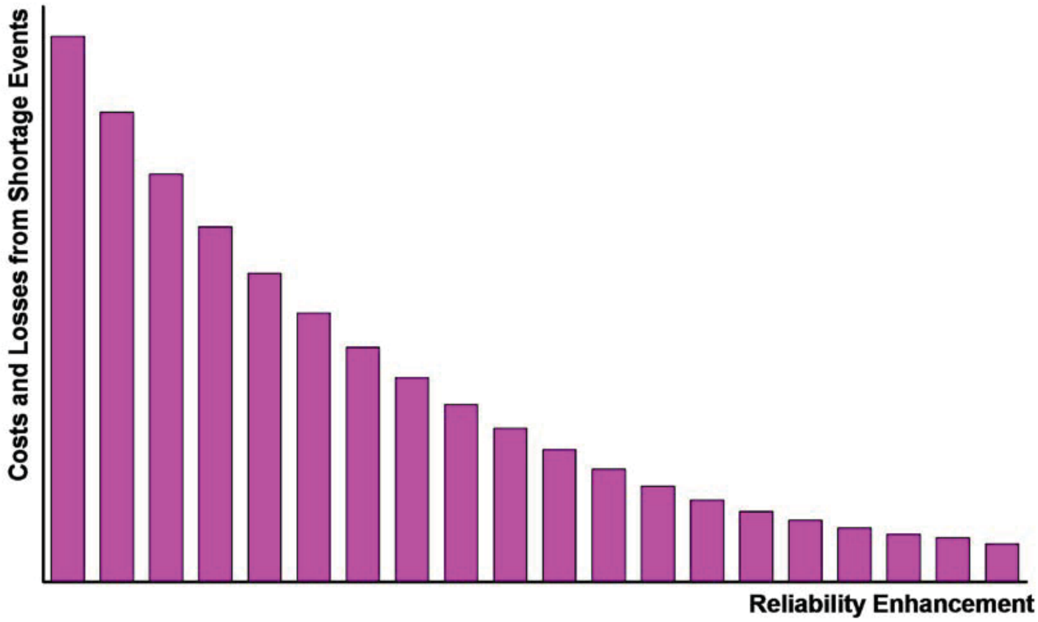
Figure above depicts the primary planning interrelationships important for evaluating, from a least-cost perspective, the cost of alternative plans to increase the reliability of a hypothetical water service system. The link between the investment in long-term water management options and the size and frequency of shortages is shown, as is the link between shortage contingency management strategies and the costs and losses associated with foregone use: a greater investment in the ability to manage shortages will lessen the economic costs and losses due to foregone use when they occur.

Theoretical Basis

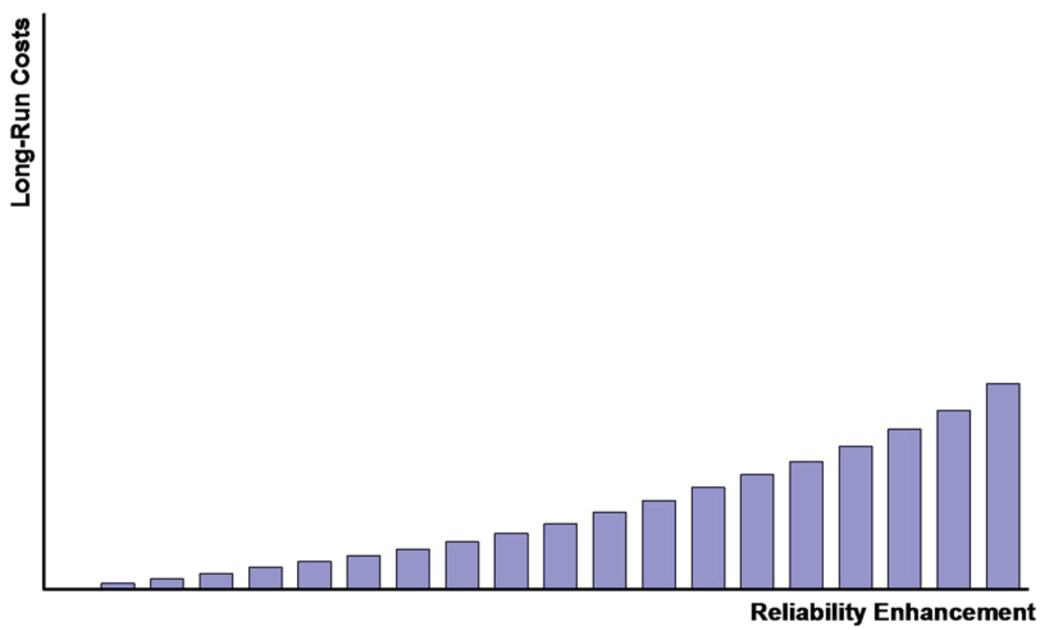
The theoretical basis of LSPSIM is to minimize the total cost of *reliability management*, the sum of two costs: *cost of unreliability* and the *cost of reliability enhancement*, recognizing that the former is inversely related to the latter.

The *cost of unreliability* is most directly measured by forgone use. Foregone use occurs when residential users or businesses, for example, have established a lifestyle or a level of economic production based on an expected level of water supply available for use and that expectation is not realized (i.e., a "shortage event") in a particular year or sequence of years.

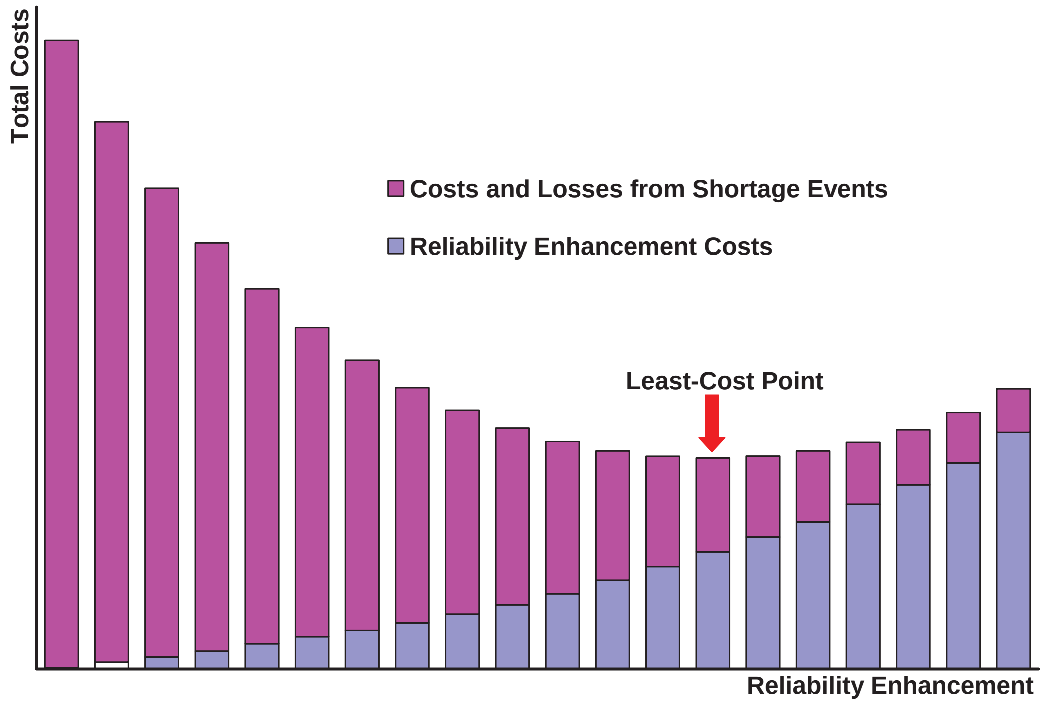
Figure below illustrates the expected decrease in the costs and losses associated with foregone use as water management options are adopted to enhance reliability. This enhancement may be obtained from either supply augmentation or demand reduction options.



The next figure shows incremental effect of enhancing reliability on long-run water management costs. The assumption is made that options will be adopted in an order inversely related to their unit cost, including any associated treatment and distribution costs: the least expensive options are expected to be adopted first.



When the information from the two Figures above is combined, it results in a total cost tied to the level of reliability enhancement as shown in the following figure:



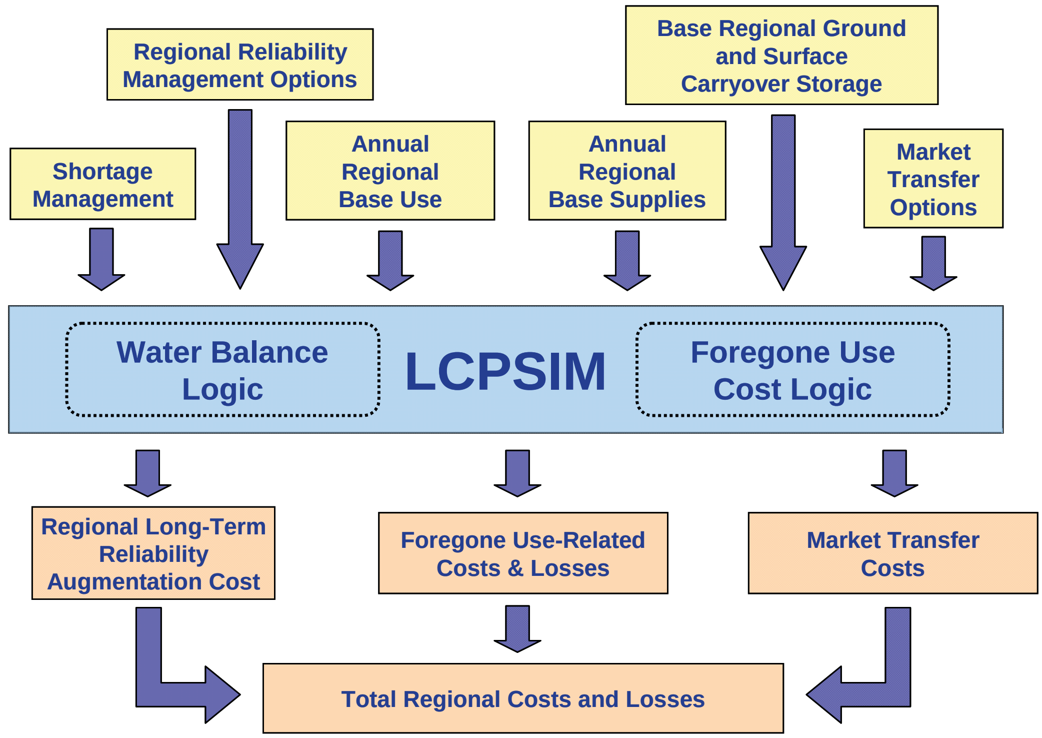
The least-cost point represents the economically efficient plan, that is, it is the level of reliability enhancement beyond which it is economically less costly, compared to the cost of additional reliability enhancement, to accept the expected costs and losses from foregone use. Conversely, at any level of enhancement less than this, compared to the expected costs and losses from foregone use, it is less costly to enhance reliability. This solution is the least-cost reliability management plan.

Numerical Basis

In LCPSIM, a priority-based objective, mass balance-constrained linear programming solution is used to simulate regional water management operations on a yearly time-step, including the operation of surface and groundwater carryover storage capacity assumed to be available to the region/planning area. The system operations context allows the evaluation of the reliability contribution of additional regional long-term reliability enhancement options, including increased carryover storage capacity, to account for any synergistic interactions between options. The cost of adding those measures is determined using a quadratic-programming algorithm which minimizes the cost of each incremental addition. The sum of the cost of unreliability (which decreases) and the cost of the adoption of the reliability enhancement options (which increases) is mapped against the increasing level of use of those reliability enhancement options and a polynomial smoothing function is fitted. The polynomial function is then solved for the least-cost reliability management plan.

Input and Output

Figure below shows the general types of both the *Input* data required by LCPSIM and the resulting *Output* information generated by the model.



Data Management

LCPSIM was developed to use CALSIM II output as its primary data source. Excel© VBA macros are used to extract time series delivery data from CALSIM II DSS files and store them as the ASCII files used by LCPSIM. Data on other regional deliveries available as time-series data are also stored as ASCII files. All system operations and regional options parameters used by the model are stored as ASCII files. Results from the model are exported in Excel® file format. Excel® VBA macros are available for interfacing LCPSIM results with CALAG shadow values to calculate the net value of "excess" urban supplies made available for agricultural use in wet and above normal years and transfers from agricultural use to urban use in dry and critical years. All input and output data are stored locally.

Software

LCPSIM software runs on Windows 95® and above and is designed to be data-driven in order to represent different water service systems without changing the model code. The semi-self-documenting source code is written in the Delphi® language (formerly, Borland Object Pascal) with an emphasis on modularity to facilitate extending the model, if needed. Compiling the source code requires Version 6 (or greater) of the Borland Delphi® Integrated Development Environment. A Windows® help file is callable from the program (a users' manual is not yet available). To run, LCPSIM requires either a proprietary quadratic programming solver DLL from Frontier Systems (very fast) or a free quadratic programming solver DLL developed by Csaba Mészáros at the MTA SZTAKI, Computer and Automation Research Institute, Hungarian Academy of Sciences, Budapest, Hungary (much slower). Licensed Delphi® IDE users can also freely distribute the Visual Components Formula One® ActiveX component required by LCPSIM.

CVP Cost Allocation Study

Description of Analytical Tools

Name

Other Municipal Water Economics Model (OMWEM)

Author

California Department of Water Resources and U.S. Bureau of Reclamation

Categories

Statistical demand function

Main Features and Capabilities

- The model includes CVP M&I supplies north of Delta, SWP and CVP supplies to the Central Valley and the Central Coast, and SWP supplies or supply exchanges to the desert regions east of LCPSIM's South Coast region.
- The model estimates the economic value of M&I supply changes in these areas as the change in cost of shortages and alternative supplies (such as groundwater pumping or transfers).
- Data from the available 2005 Urban Water Management Plans were used to estimate 2025 water demand and supplies for an average condition and a dry condition, and to identify additional water supply options and their costs.
- For a water supply scenario, OMWEM uses water deliveries, defined as the percent of SWP Table A or percent of CVP municipal contract by year.
- SWP and CVP water deliveries are provided by CALSIM II.
- If supply is insufficient to meet demand in years categorized as having below normal, above normal or wet water supply, the model calculates the cost of additional water supplies.
- If the water supply year is categorized as dry or critical, the model allows for shortfalls to be managed with dry/critical supply sources and with end-

user shortage. The shortage costs are estimated using a constant of elasticity demand function.

Applications

The model has undergone several recent updates. OMWEM now includes 2009 and 2025 development conditions. This work, reflected in the discussion above, improves the demand/supply input. The model does not include the full level of detail that may exist in local water providers' plans. Results are useful for comparing alternatives and to provide an approximate estimate of avoided cost. They should not be viewed as precise representations of individual water providers' costs or options.

Calibration/Validation/Sensitivity Analysis

The model has been updated to include the effect of real energy cost increases on water prices. The rate of increase in real water costs is assumed to be the same as the rate of increase in electricity prices. The annual rate of increase is approximately 1.3 percent. Generally, OMWEM has the same limitations as LCPSIM. In addition, decision rules about water supply costs and shortage are relatively simplistic. The areas included in OMWEM could be modeled in a LCPSIM framework. A variety of updates are being considered, primarily involving demands and water supply costs under recent conditions. A number of relatively small M&I water providers receive SWP or CVP water but are not covered by LCPSIM.

Software

The Other Municipal Water Economics model (OMWEM) is a set of compiled (individual) Excel-based spreadsheet application.

RECLAMATION
Managing Water in the West

CVP Cost Allocation Study

November 19, 2013

Description of Analytical Tools

Name
PLEXOS® Integrated Energy Model

Author/Developer
Glenn Drayton, Ph.D./Energy Exemplar LLC

Category
Power market simulation model used to evaluate CVP power accomplishments and benefits

Main Features and Capabilities
- Weekly, hourly or sub-hourly time steps
- Spatial scale – California's power grid, but with the capability of simulating the power dispatch in the entire Western Interconnection
- Using the monthly water operations and constraints simulated in the CalSim2 model as input parameters to PLEXOS, simulates hourly dispatch of CVP power features to meet load and reserve requirements while respecting electrical transmission and generation constraints in order to depict on-peak and off-peak generation and the provision of ancillary services in such a way as to accurately reflect the current and future operations of the CVP power features
- Values CVP generation attributes by modeling the power markets operated by the California Independent System Operator (CAISO) under current and year 2020 conditions when California's mandate requiring 33% of electricity used to serve load be produced from renewable resources will be fully implemented

Applications
PLEXOS is widely used for the following purposes:

- Price Forecasting
- Power Market Simulation and Analysis
- Detailed Operational Planning and Optimization of Power Plants and Grid
- Trading and Strategic Decision Support
- Generation and Transmission Capacity Expansion Planning (Investment Analysis)
- Renewable Integration Analysis

- Co-optimization of Ancillary Services and Energy Dispatch
- Transmission Analysis and Congestion Management
- Portfolio Optimization and Valuation
- Risk Management and Stochastic Optimization

PLEXOS' unique capability to model hydro generation in a dynamic manner considering the numerous regulatory and institutional constraints imposed on the hydro system makes it the ideal transmission-constrained power production model to evaluate hydropower operations and benefits. In addition to the work on the CVP Cost Allocation Study, Reclamation has contracted with Energy Exemplar to use the PLEXOS model to evaluate net power benefits of enlarging Shasta Dam, constructing Sites Off-stream Storage Reservoir with a daily pump-back operation and constructing Temperance Flat Reservoir upstream of Millerton Lake considering the impact to the Kerckhoff Power Project.

Calibration/Validation/Sensitivity Analysis

PLEXOS results have been validated in a number of settings including the 2012 Long-Term Procurement Plan (LTPP) process, which is under the purview of the California Public Utility Commission (CPUC). Every two years, the CPUC holds an LTPP proceeding to review and adopt ten-year procurement plans for California's Investor-Owned Utilities (IOUs). The LTPP evaluates the utilities' need for new resources and establishes rules for rate recovery of procurement transactions[1]. For the 2012 LTPP, the CPUC requested that the California ISO conduct a system operational flexibility modeling study. The PLEXOS model was used to perform this study for the California ISO to study the status of CAISO's power system in the year 2022[2]. The results of the 2012 LTPP study have been used to inform PLEXOS modeling for Reclamation's storage studies and will be used in the CVP Cost Allocation Study's power benefits evaluation.

PLEXOS is a very flexible modeling tool, which is ideally suited to perform such sensitivity analyses such as looking at impacts on power benefits resulting from various forecasts of natural gas prices, different hydro conditions, variations in electric load forecasts, evolving cap and trade market assumptions, etc.

Peer Review

The 2012 LTPP study reflects the inputs from multiple resources and has been reviewed by multiple stakeholders in the California power sector, as shown in Figure 1. WECC's Transmission Expansion Planning Policy Committee (TEPPC) oversees and maintains a public database for production cost and related analysis[3]. In the 2012 LTPP study, the latest TEPPC 2022 base case, along with the 2012 WECC Loads and Resources Subcommittee (LRS)'s report, were used for the

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[1] See http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/index_2012.htm

[2] See http://www.caiso.com/informed/Pages/StakeholderProcesses/RenewableIntegrationMarketProductReviewPhase2.aspx

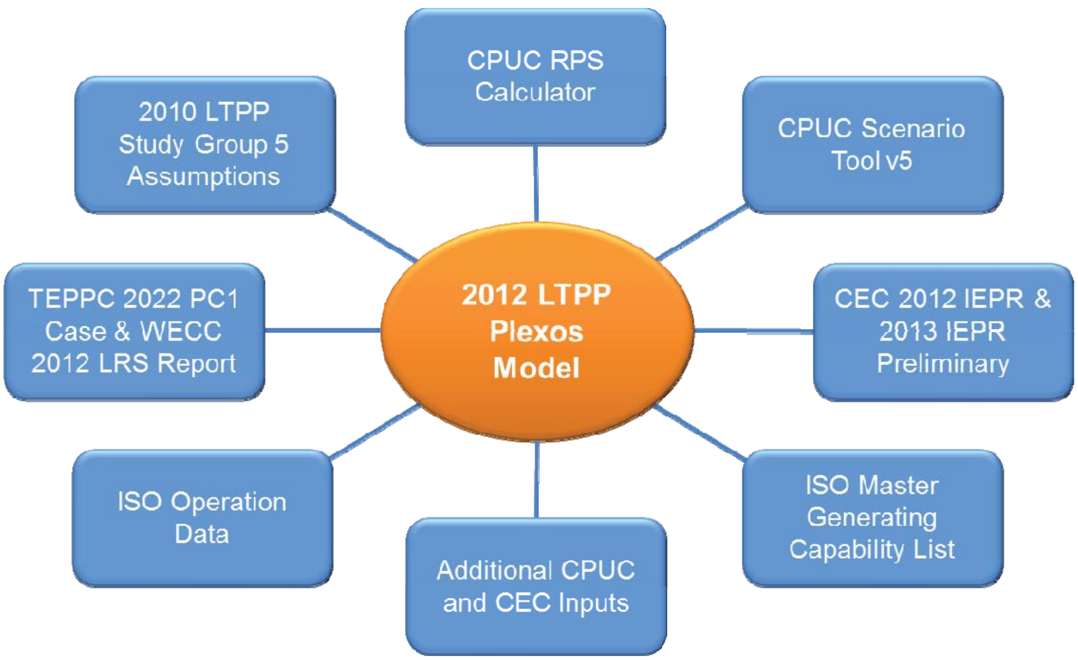
[3] See https://www.wecc.biz/committees/BOD/TEPPC/Pages/TEPPC_Home.aspx

majority of the assumptions. The assumptions within California were further updated with CPUC's inputs from 2010 LTPP assumptions, Renewable Portfolio Standards (RPS), and scenario selection tool; with California Energy Commission (CEC)'s inputs on load forecast from Integrated Energy Policy Report (IEPR) and natural gas price forecast; with California ISO's inputs on generator data and operation data, etc.

Description of PLEXOS Software

The energy and ancillary service co-optimization is the basis of the PLEXOS algorithm. The PLEXOS Mixed Integer Programming Algorithm (MIP) in SCUC/ED (Security Constrained Unit Commitment/Economic Dispatch) produces the optimal decision on the generation and reserve provisions from each generator to meet the system energy demand and reserve requirements.

Figure 1. Source of LTPP Assumptions from Multiple Resources



Source: R.12-03-014: LTPP Track II Workshop – Operating Flexibility Modeling Results

Forecast of Economic Value of CVP Power 2014-2113
Consultants' Report – Energy Exemplar LLC and Pinnacle Consulting LLC
March 2, 2017

Methodology Overview

The Central Valley Project (CVP) power benefits for this analysis are based on the principles and methodology specified by the Bureau of Reclamation (Reclamation) over the course of the study and documented in Appendix A.

The three power components to be evaluated include: (a) energy; (b) ancillary services (AS); and, (c) planning capacity.[1] The economic analysis is performed from a "national perspective rather than from the effects to a particular locality or regional standpoint." Therefore, the analysis does not represent a utility or Northern California perspective, but a societal perspective. The market price is based on marginal production costs rather than average costs. and[2] the economic analysis is based on a period of 100 years.[3] The 100-year period for this study is 2014 through 2113 as the Cost Allocation Study (CAS) base year is 2013.

This is the same methodology used by Reclamation in the Shasta Lake Water Resources Investigation and the North-of-Delta Offstream Storage Investigation. The specific methodology, tools, assumptions, results, and conclusions are described in the following sections.

[1] Ibid.
[2] Ibid.
[3] Ibid., p. 5.

Energy and Ancillary Services Derivation

The energy and ancillary services valuation is based on a forecast of the marginal cost of production (i.e. incremental costs) in the future. A sophisticated production-costing software tool, PLEXOS, is used for this analysis because it has the unique capability of simultaneously optimizing energy, ancillary services, generation, and transmission utilization.[4]

The energy and ancillary-services price forecast is then utilized to forecast the value of CVP power in the future. The steps involved in developing this forecast can be summarized as follows:

1. Develop WECC production-costing database
2. Forecast WECC hourly energy and ancillary-service prices
3. Extract hourly Northern California prices
4. Develop CVP representation in PLEXOS
5. Forecast CVP energy and ancillary-service revenue

Each of these tasks will be summarized below:

Develop WECC production-costing database – This is a very time-consuming activity that incorporates the input of all major Western Electric Coordinating Council (WECC) utilities, as well as regional, federal, and state planning and regulatory agencies. Due to complexity and cost to develop, the WECC-wide production costing database is produced only for a single year (10 years in the future) and is produced every other year. WECC coordinates this effort under the direction of its Transmission Expansion Planning Policy Committee (TEPPC).[5]

This WECC (i.e. TEPPC) database contains the most comprehensive and well-vetted set of assumptions available for WECC.[6] The TEPPC database is converted into production-costing input data for various models including PLEXOS and is used for WECC-wide transmission and other regional studies. At the time this study was initiated, the 2014 TEPPC database represented the latest set of assumptions available from WECC and projects values for the year 2024..

As in any database, there are many key assumptions that drive the results of the study. A summary of a few key assumptions from the 2014 TEPPC database is contained in Appendices A and B.

Forecast WECC hourly energy and ancillary-service prices – Once the WECC database has been developed, energy and AS prices can be derived on an hourly basis for various regional locations. These prices represent the incremental cost to provide an additional MWh of energy or MW-hour of ancillary services in that location. These prices reflect the generation mix in the region as well as the cost of imports and transmission and other major operational constraints. Due to modeling complexity and time constraints, only a limited number of ancillary-service prices are forecast. These included regulation, spin, and non-spin.

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[4] For more information regarding the model PLEXOS, please refer to www.energyexemplar.com.

[5] See https://www.wecc.biz/TEPPC/Pages/Default.aspx.

[6] The PLEXOS dataset used to determine regional energy and AS prices is from the 2014 LTPP study without any modification. For additional information see CPUC May 14, 2014 Assigned Commissioner's Ruling, 13-12-2010). This dataset represents the "Trajectory Scenario" which is 33 percent renewable and little change in existing policies.

Extract hourly Northern California prices – The WECC modeling described in the previous task provides energy and ancillary-service prices for 20 to 30 different regions in WECC, including Northern California. The Northern California hourly energy, regulation, spin, and non-spin prices are extracted from the 2024 WECC database and used in the CVP evaluation analysis.

Develop CVP representation in PLEXOS – Once the hourly prices are available and input into PLEXOS, the next step is to develop a representation of the CVP in PLEXOS. PLEXOS has a wide spectrum of options for modeling the CVP, ranging from a single unit with constraints, to modeling it as multiple units with extensive detailed constraints including water-flow limitations and time-associated requirements (i.e. "cascading waterway and storage").

For the purposes of this study, CVP is modeled with the power stations summarized in Table 1.

Table 1
CVP Modeled Hydropower Stations

Plant Name	Capacity (MW)
Trinity	139.4
Carr	154
Spring Creek	189.1
Shasta	715
Keswick	105
Folsom	207.7
Nimbus	16
New Melones	380
Gianelli	191.3
O'Neill	8.6
Total	**2,103.1**

The Gianelli and O'Neill plants are modeled as pumping-generating stations, which are optimized with a 58.82% efficiency.

The hydropower plants (or stations) summarized in Table 1 are modeled as distinct and separate resources with the following characteristics, many of which vary monthly:

- Minimum generation
- Maximum generation
- Total energy[7]
- Must-run energy
- Dispatchable energy
- Ramp-up rate[8]

[7] The total monthly energy equals the sum of the must-run and dispatchable energy. Must-run energy is often used to meet minimum water outflow requirements.
[8] The ability of a plant to go from minimum to maximum generation in terms of MW/hour. Although PLEXOS has the capability to include multiple ramp rates for a given plant, in this study only a single ramp rate was used. The plants were generally assumed to be able to go from minimum to maximum

- Ramp-down rate
- Maximum hourly regulation-up and regulation-down sales

The minimum, maximum, and total monthly energy amounts by plant were developed outside of PLEXOS and were input as constraints. These monthly values were developed by Reclamation and the California Department of Water Resources (CDWR) professionals using the CalSim[9] and LTGEN[10] models.

Two zones were then modeled in PLEXOS. The first zone represented the Northern California market. The second zone represented CVP and its resource capability. Exports from the CVP zone to the "market" zone incurred a $14/MWh[11] wheeling rate to reflect the current cost of wheeling from CVP to the California Independent System Operator (CAISO) market.[12]

Forecast CVP energy and ancillary service revenue -- In this application, the objective function of the PLEXOS model is to maximize the CVP net revenue from energy and ancillary services, subject to constraints. If the model did not have any CVP constraints, the model would move unlimited energy and ancillary services into the super-peak period where it has the most value. However, due to the constraints, the energy and ancillary services are spread out over the day and month, and therefore, more limited in terms of revenue potential.

The PLEXOS 2024 energy and ancillary-service results are summarized in Table 2 for various hydrological conditions.[13]

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generation in about ten minutes (same from ramp-down). Thus, ramp rates were not a constraint in this particular study.

[9] For a description of the CalSim model, see http://baydeltaoffice.water.ca.gov/modeling/hydrology/CalSim/Documentation/CalsimManual.pdf.

[10] For a description of the LTGen model, see Section 2, "Overview of Analytical Approach", https://www.usbr.gov/mp/SSJBasinStudy/documents/02_sec1-4.pdf..

[11] 2013 dollars.

[12] The wheeling rate to CVP members is $0/MWh. Since all exports are modeled to incur the $14/MWh rate, the CVP energy value is understated with respect to its value to CVP customers in this analysis. This wheeling assumption was made in order to reduce the complexity of the study.

[13] The analysis was originally done using 2014 dollars. These values have been deflated to 2013 dollars using the GDP implicit price deflator.

Table 2
2024 CVP Energy and Ancillary-Service Sales and Revenue[14]
(2013 $)

Parameter	Wet	Above Average	Average	Dry	Critical	Weighted Average
Energy Sales (GWh/year)	6,048	5,180	4,216	3,806	2,728	4,606
AS Sales (GW-hour)	1,044	1,047	1,049	1,049	1,048	1,047
Energy Rev. (mil. $)	237	208	175	159	116	187
AS Rev. (mil. $)	0.7	0.5	0.4	0.4	0.5	0.5
Total Rev. (mil. $)	238	209	176	159	117	187

The information below summarizes the various Northern California hydrological conditions for the water-years 1921-2003 that were used for estimating both water deliveries and power production and are categorized as follows:[15]

- Wet – 28 years
- Above normal – 13 years
- Below normal – 17 years
- Dry – 21 years
- Critical – 13 years
- Total – 92 years

The annual energy sales are a function of the monthly energy amounts derived outside of PLEXOS and input into the model. Except during relatively rare “dump” conditions, all CVP energy would be sold into the market at the prevailing price.[16]

In 2024, CVP ancillary-service sales are not forecast in PLEXOS to be particularly significant. This is a consequence of limitations placed on CVP in terms of ancillary-service capability and sales and the relatively low price compared to energy sales. The ancillary-service sales that are made are solely regulation.

The third row contains the forecast annual energy revenue for the various hydrological conditions. These amounts vary from $116 to $236 million depending on the amount of

[14] All ancillary sales modeled in this analysis are regulation, since the regulation price is higher and CVP is assumed to have limited AS production capability.
[15] Email dated Oct. 28, 2016 from N. Parker (USBR) to S. McBride and E. Toolson
[16] “Dump” conditions occur when the total minimum generation of the online resources exceeds the system load for a specific location and additional exports are not feasible. In PLEXOS, the market price of power during these dump conditions is input as a negative $100/MWh. Therefore, CVP would only generate during dump conditions due to “must-run” constraints, such as minimum instream water flows. In 2024, these dump conditions were calculated from the WECC runs to occur only about 100 hours per year.

hydropower available. The average annual energy sales price also varies from 40 to 43 $/MWh depending on hydrological conditions.[17]

The ancillary-service revenue is not significant in these cases. The average annual ancillary-service price for all five of the hydrological cases summarized in Table 2 is less than $1. That figure is consistent with the recent CAISO market where the average annual ancillary-service price for the period 2011-2015 is considerably less than $1/MW-hour.[18] In fact, for the last three years, the average annual AS cost for all services is less than $0.30/MW-hr. Since the AS revenue is relatively insignificant, the total revenue for each water-year type is very similar to the total energy revenue. CVP energy production and sales are clearly the driver of hydropower benefits in these results.

A critical assumption in the derivation of the CVP energy revenue is the 2024 Northern California natural gas price. The gas price has a direct bearing on California market in over half of all hours. As summarized in Appendix A, the Northern California (i.e. PG&E burner-tip) gas price assumed in the development of the WECC LTPP cases is $4.30/MMBtu.

Some of the participants in the study have questioned whether this is an appropriate assumption for 2024 or if the forecast gas price should be closer to $2.50/MMBtu (the approximate price earlier in the summer of 2016). This issue is discussed in Appendix C, Natural Gas Price Assumption.[19]

The recommended annual energy revenue forecast for the 100-year period is contained in the Conclusion to this report.

[17] This average annual energy price in 2024 (in 2014$) of $40-$43/MWh compares favorably with the price of WAPA power sold in 2014 which averaged $48/MWh, presentation made by Dr. Tong Wu, WAPA entitled “Western Experience of Marketing CVP Generation”, slide 9 entitled “Summary: CVP Power Products and 2014 Market Value”.

[18] CAISO “market report”, Figure E.5 “Ancillary service cost as a percentage of wholesale energy cost”, http://www.caiso.com/Documents/2015AnnualReportonMarketIssuesandPerformance.pdf.

[19] Several study participants have requested information regarding the impact of lower gas prices. If the 2024 gas price was assumed to be $2.50/MMBtu instead of the $4.30/MMBTU utilized in the study, the energy revenue in Table 8 could decrease about 20 percent. This figure is an approximation. No WECC simulations were performed with the lower gas price since this assumption was not assumed to be valid for the 100-year forecast period.

Capacity Derivation[20]

Capacity is only used once in the generation of energy and is used to provide either energy or ancillary services. However, capacity that is available for only the next day (short term) has a much different value than capacity that is available for the next 100 years (long term). It is the long-term value of this planning capacity that needs to be estimated for the purpose of this analysis.

A simple example might better explain this concept. Assume that a person can go to the gas station today and fill the car with gas at approximately $2.50 a gallon. But it is unlikely that the same person will be able to find a gas station owner who would be willing to sign a contract that would allow the car to be filled at $2.50 a gallon for the next 100 years. The gasoline is only used in “real-time” in either case. But the long-term price guarantee is a valuable contract that is priced at a significant premium over the current-day price.

This example illustrates the significant difference between a short-term (one-day) and a long-term (100-year) contract. In the end, both products deliver power in real-time, but the guarantee of freezing the long-term price at today’s values, carries a significant monetary premium. The same is true in any commodity market with a sustainable demand, including power.

CVP member utilities are able to rely on this power, subject to contractual and physical restrictions, over the long-term. As a result of these long-term contractual guarantees, the capacity qualifies as “planning capacity” that can meet a utility’s future load and reserve obligations.

The North American Electric Reliability Corporation (NERC) recommends a 15 percent “planning reserve margin” for predominately thermal systems and a 10 percent reserve margin for predominately hydro systems.[21] Most utilities in the United States, except for a few hydro-based systems in the Northwest, plan for a 15 percent reserve margin. This NERC provision has been interpreted by the utilities in California to mean 15 percent planning reserve requirement as evidenced by their filings to the California Energy Commission (CEC), where the utilities demonstrate their ability to meet a 15 percent reserve margin.[22] [23]

The value of the long-term capacity available from CVP is the product of the amount available and the estimated market price of that capacity. These two subjects are addressed separately in the following two subsections.

<u>CVP Planning Capacity Amount</u> -- In the most recent CEC filings (Capacity Resource Accounting Tables), CVP member utilities list the amount of CVP planning capacity they rely on

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[20] Planning Reserve Margin – Defined by NERC as the “amount of generation capacity available to meet expected demand in planning horizon” North American Electric Reliability Council.

[21] North American Electric Reliability Council (NERC), http://www.nerc.com/pa/RAPA/ri/Pages/PlanningReserveMargin.aspx.

[22] SMUD and NCPA “Public S-1 supply forms 04-23-15”, table “Capacity Resource Accounting Table (CRAT).

[23] The California Public Utility Commission adopted a Resource Adequacy framework in 2004 to ensure the reliability of electric service in California.[23] The concept of resource adequacy is much broader than the single index of planning reserve margin and includes policies, programs, and reliability assessments to accomplish its overall purpose.

to meet their 15 percent planning reserve requirement. In Table 3, the available CVP planning capacity information for the largest six utility recipients is summarized. The capacity amount is derived from the public sources as footnoted below and the allocation was provided by Western Area Power Administration (WAPA).[24] The capacity that the utility claims is available to meet their planning reserve margins is publically available for the SMUD, NCPA, and Redding, but not readily available for SVP, PWRPA, or Roseville (their hydro data are aggregated and not listed as separate resources).[25]

From these data, it is straight-forward to extrapolate the total CVP planning capacity amount by dividing each utility's CVP allocation by their relative percentages. This calculation is contained in the last column of Table 3. For SMUD and NCPA, the total CVP planning capacity is calculated to be about 1210 MW. For the City of Redding, the total amount is 1089 MW. The weighted amount for the three utilities for which data are available is 1190 MW.

Table 3
CVP 2024 Planning Capacity Amount

Utility[26]	CVP Capacity (MW)	CVP Percentage (%)	Total CVP Capacity (MW)
SMUD	308	25.454995 [27]	1210 MW
NCPA	229	18.879611 [28]	1213 MW
SVP	n/a[29]	9.603401	
Redding	98	9.000850 [30]	1089 MW
PWRPA	n/a	7.279168	
Roseville	n/a	4.853328	
Total	**635**	**53.335456** [31]	1190 MW

For purposes of this study, 1190 MW will be considered the total CVP planning capacity available for the years 2014 through 2113.

CVP Planning Capacity Value -- The "CVP Power Benefits Methodology" approach states that the forecast market prices be based on the "marginal production costs rather than average costs".[32] In other words, what does it cost for the next increment of demand to be produced and when is it needed.

[24] Email from R. Rieger of WAPA to S. McHale of USBR dated January 31, 2017.
[25] NCPA has expressed reservations regarding the capacity value recorded in their 2014 CEC submittal. However, no additional information has been received since the concern was expressed in a January 30, 2017 meeting at USBR.
[26] Utility abbreviations include Sacramento Municipal Utility District (SMUD), Northern California Power Agency (NCPA), Silicon Valley Power (SVP), Power and Water Resources Pooling Authority (PWRPA),
[27] SMUD 2014 CEC filing, Capacity Resource Accounting Table, Electric Resource Planning Form S-1, line 19-3.
[28] NCPA 2014 CEC filing, Capacity Resource Accounting Table, Electric Resource Planning Form S-1, line 19d.
[29] Data not available. SVP hydro is aggregated in 2014 CEC supply forms.
[30] City of Redding 2014 CEC filing, Capacity Resource Accounting Table, Electric Resource Planning Form S-1, line 19d.
[31] This is the total percentage of those utilities that have a corresponding CVP Capacity in Table 3.
[32] See Section 1 of this paper.

This is a difficult question since the California market currently has a substantial surplus of planning capacity. Additional difficult questions include: What type of capacity will be added to the system? Will the new capacity include traditional thermal resources (such as a combustion turbine or combined cycle)? Or will all of the new resources be renewables, storage, or other newer and more advanced technologies? And will these new renewable and storage resources earn sufficient revenue in markets other than long-term capacity (i.e. renewable and energy services) to effectively mitigate the need for a significant long-term capacity payment?

At the time of this study, planning reserve margins throughout California were relatively high with little load growth projected for the foreseeable future. For example, the CAISO projected planning reserve margins in excess of 34% for the summer of 2014 – more than twice the required 15% amount.[33]

By 2014, the type of new generating resources had changed from significantly from gas-fired to renewable. In 2013, the California Energy Commission records that 3,900 MW of new capacity become operational and 12% of that was considered renewable. By 2014, only 375 MW of new generating capacity was added and 100% was renewable. And for the year 2014, no new generating capacity was added in California.[34]

Given this high level of uncertainty regarding the timing and type of future planning capacity, the following sensitivity analysis was developed and summarized in this report:

Table 4
Description of Capacity-Value Sensitivity Cases

Case Description	Planning Capacity Deficit Year	Resource to Meet Capacity Deficiency
CC in 2030	2030	Combined cycle
CC in 2040	2040	Combined cycle
CC in 2050	2050	Combined cycle
No CC needed	Never	None

The same methodology is applied to each of these four cases. The capacity value in the initial year of the study is the historical value recorded in the marketplace. Based on previous information received from SMUD short-term traders, this value is assumed to be $29/kw--yr in 2013$.[35] This value is considered to be constant in real terms from 2014 through 2020.

The value in the year that the planning-capacity is projected to occur (2030, 2040, 2050, or never) is the fixed cost to build and operate the least-cost source of new capacity, minus the net

[33] California Independent System Operator (CAISO), 2014 Summer Loads and Resources Assessment, "Summer 2014 Supply and Demand Outlook (Planning Reserve Margins), Table 1, p. 6.
[34] California Energy Commission, Energy Facility Status, http://www.energy.ca.gov/sitingcases/all_projects.html.
[35] Based on conversations between E. Toolson and SMUD short-term traders over the last couple of years. This value is subject to updating, if more recent or documentable information becomes available.

revenues expected from the marketplace.[36] This value is assumed to be the same annually (in real dollars) throughout the remaining 100-year CVP economic analysis.[37]

For the case in which new planning-reserve capacity is assumed to not be needed throughout the term of the study, the forward-looking fixed costs (net market revenues) of the most-recently built combined cycle units must still be recovered in the market or the units will be retired.

The annual value of planning capacity in the interim years between current conditions and the first year of deficiency is subject to much speculation. For purposes of this study, it has been assumed that the current real market value will remain constant through 2020, when the value will escalate at a constant real rate until the assumed capacity deficiency year.

The value of planning capacity for the deficit period is based on the least-cost resource able to provide this type of reserve. Generally, this resource has been assumed to be a combustion turbine (CT) or a combined cycle (CC) generating unit. The annual net costs for these two types of units in are summarized in Table 5.

Table 5
Net Costs for Combustion Turbine and Combined Cycle Units[38]
(2013 $)[39]

Parameter	Units	Combined Cycle	Combustion Turbine
Capacity	MW	500	100
Heat Rate[40]	Btu/KWh	7,100	9,300
Financing Costs	$/kw-yr	87.5	104.0
Insurance	$/kw-yr	6.6	7.9
Ad Valorem[41]	$/kw-yr	8.7	10.4
Fixed O&M	$/kw-yr	43.0	34.1
Taxes	$/kw-yr	16.8	16.8
Total Fixed Costs	$/kw-yr	162.4	173.3
Net Revenue	$/kw-yr	38.9	35.2
Net Fixed Costs	**$/kw-yr**	**123.5**	**138.1**

36 Net revenues are defined as the gross energy and ancillary-service revenue earned from the marketplace, minus the net costs of providing those services (i.e. variable fuel and O&M).
37 The assumption means no real escalation of capital and fixed operating costs and no real escalation or change to net revenue.
38 California Independent System Operator (CAISO), "2015 Annual Report On Market Issues and Performance", http://www.caiso.com/Documents/2015AnnualReportonMarketIssuesandPerformance.pdf, p. 53-56.
39 These figures are originally in 2015 dollars and have been deflated to 2013 dollars using a multiplier of 0.983.
40 At maximum generating capacity.
41 An Ad Valorem is determined based on the value of the facility.

Based on the information shown in Table 5, the net annual costs for a new combined cycle are about 10 percent lower than the comparable costs for a combustion turbine. Therefore, for purposes of this study, the net cost of a combined cycle will be used as the least-cost source of planning reserves once (or if) a planning capacity deficiency occurs. These costs will be valued at $124/kw-year in 2013 dollars.[42]

On the other hand, if a planning-capacity surplus situation exists throughout the 100-year planning horizon, then recently-built combined cycle units need only meet their forward-looking operating costs. In this case, the net forward-looking fixed operating costs are $36/kw-year.[43]

The specific market value assumptions for the four cases outlined in Table 4 are summarized in Table 6 below. As explained in the preceding paragraphs, the market value in 2014 is assumed to be $29/kw-yr (2013 $). This value remains constant in real dollars through 2020. Starting in 2021, the capacity value is escalated at a constant real rate until new planning capacity is needed.

Table 6
Projected Annual Planning Capacity Costs for Alternative Cases
(2013 $/kw-yr)

Year	CC in 2030	CC in 2040	CC in 2050	No CC
2016	$29	$29	$29	$29
2020	$29	$29	$29	$29
2025	$60	$42	$37	$36
2030	$124	$60	$47	$36
2040	$124	$124	$77	$36
2050	$124	$124	$124	436
2100	$124	$124	$124	$36
2113	$124	$124	$124	$36
Levelized	$91	$80	$71	$34

The key values which are input into the table and drive the rest of the analysis are highlighted in turquoise. For example, in the first case, assuming that a new combined cycle is required in 2030, the key input values are $29/kw-yr for 2016 and 2020, and the total forward-looking combined cycle costs of $124 in 2030. The other cases are similarly constructed. The remaining values in the table are derived from these key input values.

The 100-year levelized value for the four cases are $91, $80, $71, and $34/kw-year respectively. The capacity value in the last case is much lower than the other three since it is based on two critical assumptions: (1) no future planning capacity is needed; and, (2) the net

[42] Rounded to the nearest $1/kw-yr.
[43] The net forward-looking costs for a CC are $124/kw-yr as summarized in Table 5. If the unit is recently constructed, the financing costs can be avoided, and the cost is $124-$88 or $36/kw-yr in 2016 dollars.

forward-looking costs of a CC are only \$36/kw-yr.[44] Appendix C contains the 100-year detailed calculations.

The recommended capacity planning value is the “No CC” scenario and is contained in the Conclusion to this report.

[44] The \$36/kw-year is equal to the total levelized CC cost of \$124/kw-yr minus the financing cost of \$88/kw-yr (see Table 5).

Summary and Conclusion

This analysis projects the value of the power produced by the Central Valley Project (CVP) over the 100-year period from 2014 through 2113. This study is based on two salient assumptions:

- There is an efficient, transparent, and functioning energy, ancillary-services, and planning-capacity marketplace for that period.
- The majority of new generation will need to recover all of its costs from the marketplace.

For an existing unit, total cost is equal to fixed and variable operating costs. For a new unit, the total cost is equal to all construction costs plus fixed and variable operating costs.

It is likely that many new generating units will be built in the next 100 years. Most will bring specific attributes in the generation mix including energy efficiency, renewable, storage, and very flexible power. It is uncertain, however, whether any new conventional thermal generation will be needed during this time period. That uncertainty makes this analysis more difficult.

Projecting into the future, there are multiple current and potential energy products that may be bought and sold in the market, as utilities and system operators strive to meet their load requirements economically and reliably. Some of these market products are listed in Table 7.

Table 7
Current and Potential Products in the Electric Power Marketplace

Product	Included in Analysis	Notes
Planning capacity	Yes	Modeled outside of PLEXOS
Energy	Yes	CVP has significant energy-production flexibility constraints
Regulation	Yes	CVP regulation-up and down limited to 60 MW in all hours
Renewable credit	No	Not applicable for most of CVP
Flexible capacity[45]	No	CVP flexibility significantly limited
Congestion revenue rights	No	Assumed not applicable to CVP

The following assumptions and observations are critical in developing a recommended planning capacity value:

1. ***New and existing resources will need to cover their existing and future costs with revenue from the marketplace as discussed previously in this paper.***

[45] May not be a future market product, but a procurement requirement. Source: CAISO "Market and Infrastructure Policy, Draft Final Proposal, July 26, 2012, https://www.caiso.com/Documents/DraftFinalProposal-FlexibleCapacityProcurement.pdf.

2. ***There will be new and significant future markets that are either not in existence today or are just developing.*** Government mandates create new markets. For example, California is considering a 50 percent renewable mandate by the year 2030.[46] This is a significant increase over the current Renewable Portfolio Standard (RPS) of 20 percent by 2020. This potential mandate causes an increase in demand for renewable resources (thus causing the market price to increase). Even the existing value of renewable can be considerable. As an example, according to the Department of Energy (DOE), in those markets where a minimum level of renewable energy is required, Renewable Energy Credits (RECs) are currently as high as $60/MWh.[47]

   Another California mandate that will create demand and an associated market is energy storage. In October 2013, the California Public Utilities Commission (CPUC) approved a proposed mandate for 1,300 MW of energy storage to the California system by 2020.[48]

   With the increased variability and uncertainty of additional renewable resources, increased system flexibility will also be required.[49] This variability has caused some system operators to define and establish a new market for "flexible capacity".[50]

   The above paragraphs illustrate that new markets are being created for new system requirements. It is anticipated that if these markets provide significant revenue, newly-built resources will earn much of their future revenue from these new markets, thus requiring less revenue from a traditional planning reserve market.

3. ***These new markets will reduce the capacity planning payment.*** The supply of existing and future resources that can provide renewable, storage, or very flexible capacity is quite limited. The demand for new resources that can provide one or more of these attributes is greater than the existing supply. This situation causes a twofold expectation: (1) the majority of new resources will provide one or more of these attributes; and, (2) the market prices paid for these attributes will be substantia due to the limited supply. Given this future market expectation, new resources can be expected to pay for their forward-looking fixed costs from these new markets, instead of relying primarily on a traditional planning capacity payment. This phenomenon is already observable in the California marketplace as massive cancellations of conventional

[46] Energy and Environmental Economics (E3) report entitled "Investigating a Higher Renewables Portfolio Standard in California, January 2014, p. 3.
[47] US Department of Energy (DOE), "Energy Efficiency and Renewable Energy", Compliance Markets for RECS, http://apps3.eere.energy.gov/greenpower/markets/certificates.shtml?page=5.
[48] "California Passes Huge Grid Energy Storage Mandate", Green Tech Media, Jeff st. John, October 17, 2013. https://www.greentechmedia.com/articles/read/california-passes-huge-grid-energy-storage-mandate,
[49] "Evolution of Wholesale Electricity Market Design with Increasing Levels of Renewable Generation", National Renewable Energy Laboratory, September 2014, p. 14/139.
[50] Flexible capacity generally means energy resources which can ramp-up and ramp-down as quickly as needed, potentially starting up and shutting down multiple time a day. http://sustainableferc.org/caisos-flexible-capacity-proposal-approved-by-ferc/.

thermal projects in California have occurred and little or no new thermal plants being proposed.[51]

4. ***The Central Valley Project will earn minimal revenue from these new markets.*** The value of CVP power in each of the markets is very limited. Large hydro projects are not considered to be renewable in California. Therefore, no renewable credit is available. Second, the CVP has very minimal storage capabilities. And third, the CVP is assumed to have very limited flexibility due to other competing project purposes such as water deliveries, fisheries, recreation, and others.

Given that the CVP project has significant physical and contractual constraints and is limited in its ability to participate in these markets, we do not expect that the CVP revenues will be equivalent to those required to build a new generating unit. Therefore, we recommend the following forecast be used to value the CVP project over the period of 2014 through 2113.

Table 8
Recommended CVP Power Values for the Period of 2014 through 2113
(2013 $) [52]

Product	Levelized (mil. $)	Present Value (mil. $)
Planning capacity	41	1,202
Energy	187	5,508
Ancillary services	1	15
Total	**229**	**6,725**

The total levelized value of CVP power through the 100-year period is forecast to be approximately $230 million per year. The present-value of power over the same 100-year period is about $6.7 billion. Based on this analysis, energy production accounts for about 82 percent of the total value.

51

52 Values are rounded to two significant digits.

Appendix A
Key Assumptions – 2014 TEPPC WECC Database
(2014 $)

- Model year – 2024 (in 2014 dollars)
- WECC planning reserve margin – 22 percent
- CA 2015-24-year energy load growth – 0.33 percent
- CA 2014-24 resource additions – 7,500 MW (nameplate, mostly renewable)
- PG&E burner-tip gas cost -- $4.30/MMBtu
- CVP export wheeling rate -- $14/MWh
- CA CO2 emission cost -- $23.27 per ton
- CO2 wheeling adder
    - BPA to CA -- $2/MWh
    - Other NW or SW to CA -- $10/MWh
- Nuclear resources – Diablo Canyon at 2240 MW

Appendix B
CVP-Specific Assumptions

Summary of CVP Monthy Assumptions					
Month	**Maximum Capacity (MW)**	**Minimum Capacity (MW)**	**Must-Run Energy (GWh/mo)**	**Dispatchable Energy (GWh/mo)**	**Total Energy (GWh/mo)**
Jan	1551.7	46.5	239.2	26.6	265.7
Feb	1620.9	49.5	228.4	25.4	253.8
Mar	1685.5	44.7	239.2	26.6	265.8
Apr	1729.3	45.0	275.5	30.6	306.1
May	1733.1	52.0	381.4	42.4	423.8
Jun	1710.8	69.7	413.1	45.9	459.0
Jul	1655.8	84.9	498.6	55.4	554.0
Aug	1564.2	63.9	398.3	44.3	442.6
Sep	1498.2	48.6	284.2	31.6	315.8
Oct	1462.7	40.1	207.3	23.0	230.3
Nov	1461.6	45.2	191.0	21.2	212.2
Dec	1490.4	41.8	192.8	21.4	214.2
Average	1597.0	52.7	295.8	32.9	328.6
Total	n/a	n/a	**3549.1**	**394.3**	**3943.4**

- CVP ramp rates
  - Energy and ancillary-service ramp rates considered as non-binding constraints
  - CVP energy and ancillary-service production can ramp up minimum to maximum capacity within an hour
  - CVP energy and ancillary-service production can ramp down from maximum to minimum capacity with an hour

- CVP regulation production
  - Same amount of regulation-up and regulation-down sold every hour
  - Limited each hour to 60 MW on a CVP wide basis

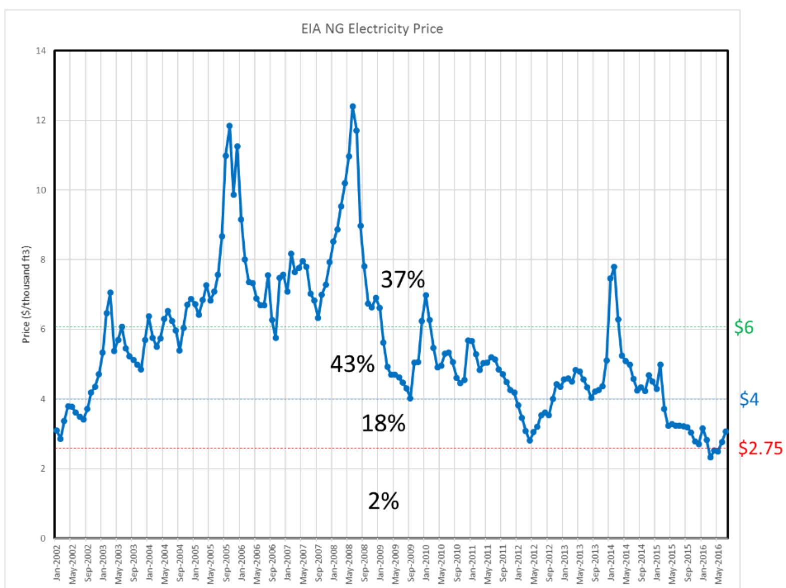
Appendix C
Natural Gas Cost Assumption

As mentioned in the Energy Section of this report, this study assumed that the PG&E burner-tip natural gas price is $4.30/MMBtu in 2024 (in 2014 $). Some of the participants in this study believed that a 2016 current market price would be more appropriate and suggested using a price closer to $2.50/MMBtu. This appendix discusses the reasons for using the original $4.30/MMBtu assumption.

1. Since the energy and AS revenue for 2024 are used to represent the entire 100-year period from 2014 through 2113, it is unlikely that there would be no real escalation in natural gas prices for this period. It is much more defendable to assume a long-term real escalation rate, even if it is very conservative.

2. The $4.30/MMBtu natural gas price was derived through an extensive WECC region-wide process and reflects the best thinking of natural gas experts at that time. We are reluctant to start changing the 2014 WECC and LTPP assumptions individually without reviewing updates to the entire dataset.

3. EIA pricing data on Natural Gas from 2002-2016 shows pricing was above $4.00 for 80% of the time, indicating that $4.30 is a more appropriate assumption[39].



Appendix D
Calculation of 100-Year Capacity Value

Assumptions	Value	Units	
- first year	2014	year	
- real discount rate	3.25%	percent	
- 2016 nominal value	$29	$/kw-yr	2013$
- total CC cost	$124	$/kw-yr	2013 $
- CC operating cost	$36	37$/kw-yr	2013 $
- CVP Planning Capacity	1190	MW	see Table 3

esc. period		2020-2030	2020-2040	2020-2050	2020-2025
esc. rate		15.54%	7.49%	4.98%	4.50%

	Year	CC in 2030 ($/kw-year)	CC in 2040	CC in 2050	No CC
1	2014	29	29	29	29
2	2015	29	29	29	29
3	2016	29	29	29	29
4	2017	29	29	29	29
5	2018	29	29	29	29
6	2019	29	29	29	29
7	2020	29	29	29	29
8	2021	34	31	31	30
9	2022	39	34	32	32
10	2023	45	36	34	33
11	2024	52	39	35	35
12	2025	60	42	37	36
13	2026	69	45	39	36
14	2027	80	48	41	36
15	2028	93	52	43	36
16	2029	107	56	45	36
17	2030	124	60	47	36
18	2031	124	64	50	36
19	2032	124	69	52	36
20	2033	124	75	55	36
21	2034	124	80	58	36
22	2035	124	86	60	36
23	2036	124	93	63	36
24	2037	124	99	67	36
25	2038	124	107	70	36
26	2039	124	115	73	36

27	2040	124	124	77	36
28	2041	124	124	81	36
29	2042	124	124	85	36
30	2043	124	124	89	36
31	2044	124	124	94	36
32	2045	124	124	98	36
33	2046	124	124	103	36
34	2047	124	124	108	36
35	2048	124	124	114	36
36	2049	124	124	119	36
37	2050	124	124	124	36
38	2051	124	124	124	36
39	2052	124	124	124	36
40	2053	124	124	124	36
41	2054	124	124	124	36
42	2055	124	124	124	36
43	2056	124	124	124	36
44	2057	124	124	124	36
45	2058	124	124	124	36
46	2059	124	124	124	36
47	2060	124	124	124	36
48	2061	124	124	124	36
49	2062	124	124	124	36
50	2063	124	124	124	36
51	2064	124	124	124	36
52	2065	124	124	124	36
53	2066	124	124	124	36
54	2067	124	124	124	36
55	2068	124	124	124	36
56	2069	124	124	124	36
57	2070	124	124	124	36
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61	2074	124	124	124	36
62	2075	124	124	124	36
63	2076	124	124	124	36
64	2077	124	124	124	36
65	2078	124	124	124	36
66	2079	124	124	124	36
67	2080	124	124	124	36
68	2081	124	124	124	36
69	2082	124	124	124	36

	70	2083	124	124	124	36
	71	2084	124	124	124	36
	72	2085	124	124	124	36
	73	2086	124	124	124	36
	74	2087	124	124	124	36
	75	2088	124	124	124	36
	76	2089	124	124	124	36
	77	2090	124	124	124	36
	78	2091	124	124	124	36
	79	2092	124	124	124	36
	80	2093	124	124	124	36
	81	2094	124	124	124	36
	82	2095	124	124	124	36
	83	2096	124	124	124	36
	84	2097	124	124	124	36
	85	2098	124	124	124	36
	86	2099	124	124	124	36
	87	2100	124	124	124	36
	88	2101	124	124	124	36
	89	2102	124	124	124	36
	90	2103	124	124	124	36
	91	2104	124	124	124	36
	92	2105	124	124	124	36
	93	2106	124	124	124	36
	94	2107	124	124	124	36
	95	2108	124	124	124	36
	96	2109	124	124	124	36
	97	2110	124	124	124	36
	98	2111	124	124	124	36
	99	2112	124	124	124	36
	100	2113	124	124	124	36
c	**present value ($/kw-yr)**		**2686**	**2357**	**2101**	**1010**
a	**levelized ($/kw-yr)**		**91**	**80**	**71**	**34**
d	**present value (mil. $)**		**3196**	**2805**	**2500**	**1202**
b	**levelized (mil. $)**		**108**	**95**	**85**	**41**