Time Dependent Valuation of Energy

for Developing Building Efficiency Standards

2008 Time Dependent Valuation (TDV)

Methodology Report

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Table of Contents

List of Tables

List of Figures

List of Equations

1 Overview

1.1 General Principles

The Title 24 building standards are based upon the cost-effectiveness of efficiency measures that can be incorporated into new buildings in California. The standards promote measures that have a greater value of energy savings than their cost. The Title 24 standards are flexible enough to allow building designers to make trade-offs between energy saving measures using computer analysis methods that evaluate the relative energy performance. For example, the energy losses from having more windows in a building design can be offset by better insulation or a higher efficiency air conditioner. Historically, within the Title 24 methodology, the value of energy efficiency measure savings had been calculated on the basis of a “flat” source energy cost, which does not vary by season, or by day-of-the-week, or by time-of-day.

Beginning with the 2005 standards update, time-dependent valuation (TDV) has been used in the cost-effectiveness calculation for Title 24. This allows the Title 24 efficiency standards to provide more realistic signals to building designers, encouraging them to design buildings that perform better during periods of high energy cost. The concept behind TDV is that energy efficiency measure savings should be valued differently at different times to better reflect the actual costs to users, to the utility system, and to society. For example, the savings of an energy measure that is very efficient during hot summer weekday afternoons would be valued more highly than a measure that achieves efficiency during the off-peak. This kind of savings valuation reflects the realities of the energy market, where high system demand on summer afternoons drives electricity prices much higher than during, say, night time hours in mild weather.

This report extends and modifies TDV to accommodate electric demand response (DR) measures. Examples of measures that can provide demand response are programmable controllable thermostats and addressable dimmable ballasts. Demand response focuses on reducing energy usage for a relative few hours per year, and the ability of an entity such as the electric utility or the California Independent System Operator (CAISO) to trigger the energy reduction with limited notice. With this update, the same TDV values can be used to evaluate the continuum of demand response and energy efficiency measures.

This report on the 2008 TDV methodology has been developed to document the approach and specific formulae used to compute the benefits of demand response and energy efficiency in Title 24. This report also briefly highlights the differences between the DR modified TDV methodology for 2008 and the 2005 TDV methodology as well as the California Public Utility Commission (CPUC) energy efficiency avoided cost methodology[1]. The CPUC avoided cost methodology is discussed because it is the equivalent valuation methodology for public goods charge (PCG) energy efficiency and has many similarities to TDV.

This report focuses on the equations and methodology. In parallel, we have developed a report that documents the input data assumptions and provides web links to output files and the spreadsheets used to create the TDV values.

The basic concepts and approach used to develop the TDV methodology are the following;

1) **Rational and Repeatable Methods**
   We have used published and public data sources for the fundamental analysis approach to developing TDV data. This will allow future revisions of the Standards and their underlying TDV data to be readily updated when called for by the California Energy Commission (CEC).

[1] The CPUC avoided cost methodology can be downloaded at http://www.ethree.com/cpuc_avoidedcosts.html

2) **Based on Costs Not Rates**
We have avoided using current retail rates to value energy savings because they are based on averages over time periods and are influenced by many factors other than cost. Furthermore, there are numerous rates among the different utilities, and the rate schedules are changed frequently, so it would be unclear which to choose for the basis of standards over a long time period. However, the hourly TDV values have been adjusted so that the average customer would have the same bill using TDV values as the average class rate.

3) **Seamless Integration within Title 24 Compliance Methods**
We have assumed that the mechanics of TDV should be transparent to the user community, i.e., that compliance methods should remain familiar and easy, and that any computational complexities will take place "behind the" where the user need not be concerned with the details.

4) **Climate Zone Sensitive**
As with the weather data used for Title 24 performance calculations, which allow building designs to be climate responsive, the TDV methodology should also reflect differences in costs driven by climate conditions. For example, an extreme, hot climate zone should have higher, more concentrated peak energy costs than a milder, less variable climate zone.

5) **Hourly Valuations**
TDV is based on a series of 8760 values of energy cost, one for each hour of the typical CEC weather year. TDV values are available for each of the sixteen climate zones, for residential and for nonresidential buildings, and for electricity, natural gas and propane. Hourly energy savings estimates for a typical year are developed for a given building using a CEC-approved computer simulation tool, and those savings are then multiplied by each hour's TDV value. The sum of these values is the annual savings.

6) **Components of TDV for Electricity**
The TDV method develops each hour's electricity valuation using a bottom-up approach. We sum elements of forward-looking incremental costs, and then scale up to equal the average retail price for residential and non-residential customers. The resulting hourly TDV valuations vary by hour of day, day of week, and time of year. The components are:

   a) Generation Costs – *variable by hour* – The total annual generation cost for electricity is allocated according to long term CEC generation forecasts of wholesale electricity prices, which vary by hour of the year. The hourly generation costs include the cost of procuring generation capacity during the peak hours.

   b) Transmission and distribution (T&D) Costs – *variable by hour* – The total annual T&D costs, allocated as a function of outdoor temperature in the CEC weather files by climate zone, with the highest costs allocated to the hottest temperature hours. Non-peak hours are not allocated any T&D costs.

   c) Revenue neutrality adjustment – *fixed cost per hour* – The remaining, fixed components of total annual utility costs – taxes, metering, billing costs, etc. – are then calculated and spread out over all 8760 hours. The result, when added to the previous two variable costs for the year, is an annual total electricity cost valuation that corresponds to the total electricity revenue requirement of the utilities.

   d) Emissions Costs – *variable by hour* – Total annual emissions costs, as adopted by the CPUC for energy efficiency, are included for CO_2, PM10, and NOx. Emission costs are calculated based on the implied heat rate of the marginal unit as calculated from the generation costs.

   e) Customer Impacts – Loss in value endured by the DR participant due to demand reduction during a DR event. For example, the discomfort of higher indoor temperatures when a PCT increases the air conditioner set point during an event.

   f) Customer Outage Costs – Average loss in value or costs incurred by electric utility customers during a service interruption (blackout).

7) **Combined Electricity Costs**

The following graph illustrates how the component costs a through d add up over a Monday to Friday summer work week. The Wednesday of that week is very hot so that some of the T&D costs are allocated to the middle of the week shown in orange. The top of the curve represents the total cost for each, while the different colored regions indicate how much of each component contributes to each hour.

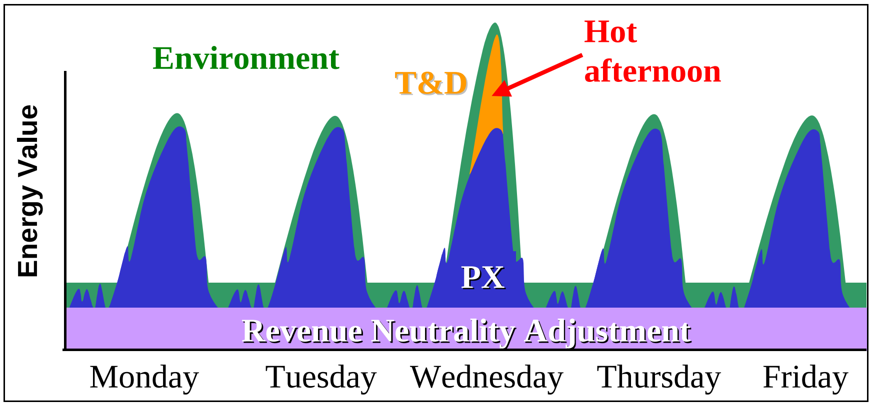


Figure 1: Hourly Variation in Components of Electricity Cost during Summer Weekdays

Component e (Customer Impacts) is a negative value associated with DR dispatch, and is not included in the figure. Component f (Customer Outage Costs) only applies during system emergencies when sufficient power cannot be delivered to customers. In those system emergency cases, the Energy Value shown above would be replaced by the customer outage cost.

8) **Components of TDV for Natural Gas**

The natural gas TDV is based on a long-run forecast of retail natural gas prices and the value of reduced emissions of CO, PM10, and NOx. The components are:

a) Retail price forecast - *monthly variation* - The natural gas forecast is based on the long-run forecasts of retail natural gas prices. There is a monthly variation in natural gas retail prices, but not an hourly variation.

b) Emissions Costs - *variable by hour* – Emission value is calculated based on the emissions rates of combusting natural gas in typical appliances and the emissions costs as adopted by the CPUC for energy efficiency.

9) **Combined Natural Gas Costs**

The following graph illustrates the components for natural gas.

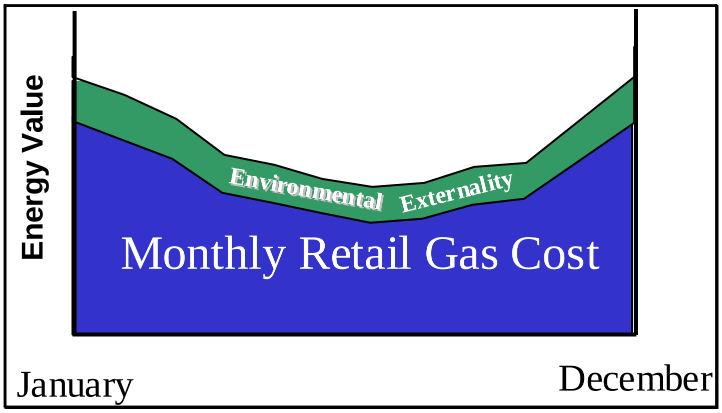


Figure 2: Monthly Variation in Natural Gas Components

10) **Components of TDV for Propane Costs**
The components of propane vary by month like natural gas. The components are:

a) Commodity Cost - *monthly variation* - The propane forecast is based on the long-run DOE forecast. There is a monthly variation in propane commodity costs, but not an hourly variation

b) Revenue neutrality adjustment (retail markup)- *fixed cost per hour* - The remaining, fixed components of total delivered propane costs are calculated and spread over all hours. Since the delivery component for propane are flat throughout the year, these are included in the revenue neutrality adjustment. Since propane is an unregulated market, the revenue neutrality adjustment is equivalent to the "retail markup" a distributor would charge on top of the wholesale price.

c) Emissions Costs - *fixed cost per hour* - The emissions costs are based on emissions trading prices and the rates of emission of propane combustion. This is an optional component based on a policy decision on whether to value air emission reductions from energy efficiency.

11) **Combined Propane Costs**

Figure 3 shows the monthly variation breakdown of the propane costs.

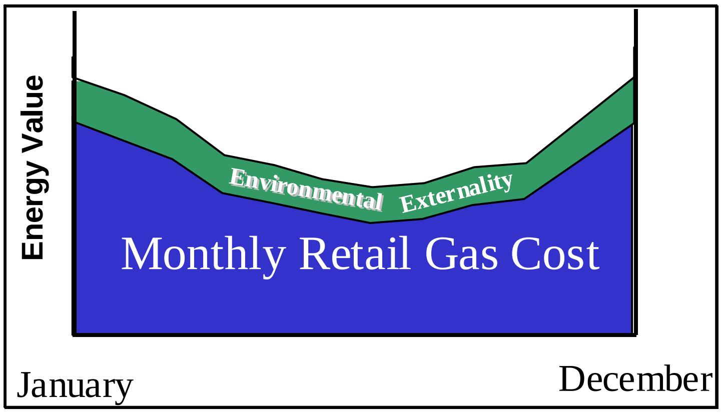


Figure 3: Monthly Variation in Propane Components

The TDV methodology for the 2005 Title 24 standards was developed to allocate the value of energy savings in a way that reflects the real costs of energy over time. While the details of the methodology can be complex, at root the concept of TDV is quite simple. It holds the total cost of energy constant at forecasted retail price levels. It then gives more weight to on-peak hours and less weight to off-peak hours.

The update for 2008 builds upon the previous TDV methodology, and makes modifications and additions necessary to value the unique characteristics of DR measures. As discussed in detail later in this cookbook, the DR modifications recognize the capacity value of resources with limited hours of operation. The modifications also quantify the customer productivity and comfort "costs" of demand response as well as the benefit of reduced customer outages.

The overall stringency of the Title 24 standards would not be changed by adopting this version of TDV, but measures that perform better on-peak would be given somewhat greater value than measures that do not. For many measures, which perform about the same in both peak and off-peak time periods, the DR-adjusted TDV would have little or no effect. Over time, Standards based on DR-adjusted TDV would tend to encourage DR measures that would provide the State with a flexible tool for reducing peak demands in times of high prices or system emergencies. This flexibility would benefit both consumers and utilities.

1.2 Data Used in TDV Calculations

The input data used in the calculation of the TDVs is described in an accompanying report on input data which describes the sources of all data used, and includes links to the spreadsheets that contain the actual numbers.

1.3 Climate Zone Mapping

The data for each respective utility described above were mapped to climate zone with the following mappings. For those climate zones with more than one utility, the utility shown in bold was used. This was selected by using the utility that serves the most customers in the zone.

Table 1: Climate Zone Mapping

Climate Zone	Utility
1	PG&E
2	PG&E
3	PG&E
4	PG&E
5	**PG&E** (SCE)
6	SCE
7	SDG&E
8	SCE
9	SCE
10	**SCE** (SDG&E)
11	PG&E
12	PG&E
13	PG&E
14	**SCE** (SDG&E)
15	**SCE** (SDG&E)
16	**PG&E** (SCE)

2 Introduction: TDV Formulation

The process used to calculate the TDV values is documented in this report so that all interested stakeholders can understand the mechanics behind developing the DR-adjusted Time Dependent Values (TDVs).

The same basic approach is used to develop the lifecycle TDV values for each of the three fuels affected by the standards; electricity, natural gas, and propane. The underlying concept behind these values is to reflect the underlying hourly 'shape' of the total costs of each fuel including wholesale market costs, delivery, and emissions costs, and the 'level' of forecasted retail rates. The average residential and non-residential load shapes will result in the same total energy cost using TDVs as with class-average retail rates. However, because the societal costs are higher during peak use of each of these fuels, energy savings during the peak periods would be emphasized. Energy savings during off-peak periods would be de-emphasized.

2.1 DR Adjustments and TDV Updates

While some technologies with demand response characteristics are addressed in the 2005 Standards, the current TDV and CPUC methodologies are primarily focused on the evaluation of long-lived measures that reduce energy usage during a significant number of hours per year, reflecting the expected value of energy efficiency over a 20-year or longer period. Since demand response measures can be dispatched during times of greatest need, the value of demand response must be estimated during 'stress' cases of extreme events such as California Independent System Operator (ISO) stage alerts, major supply or transmission outages, unusually high electricity or gas market prices, or other system events. A DR-adjusted methodology also needs to reflect the interplay between program design, customer behavior, and dependable demand reductions.

Table 2: Major Changes in the DR-Adjusted TDV Methodology for 2008 Standards

Change Level	DR-Adjusted TDV	Method Used in 2005 TDV	Method Adopted in CPUC Avoided Cost Proceeding
***	Peak period generation avoided costs adjusted upward to reflect the installed cost of a simple cycle combustion turbine (CT).	No adjustment is made.	No adjustment is made.
*	Non-peak period generation avoided costs adjusted downward so that the annual average avoided cost equals the long-run cost of a combined cycle gas turbine (CCGT).	No adjustment is needed, however, in both the annual average avoided cost equals a CCGT all-in cost.	No adjustment is needed, however, in both the annual average avoided cost equals a CCGT all-in cost.
*	Generation hourly avoided cost shape based on 1999 PX day ahead market prices.	Generation hourly shapes based on Multisim simulation runs and PX data.	Hourly shapes from 1998 through 2000 PX day ahead market (excluding energy crisis months)
***	Update of natural gas prices based on 2005 forecasts	Circa 1998 natural gas forecast	Circa 2004 natural gas forecast
*	Update of utility T&D avoided costs, using CPUC avoided cost numbers.	Circa 1998 utility costs from filings.	Circa 2003 avoided costs using uniform methodology
****	Consideration of avoided customer	Not used	Not used

	outages		
****	Consideration of adverse impacts on customers when DR is operated	Not used	Not used
*	Update emission costs using CPUC values and updated hourly generation shape.	Representative emissions for three types of generation plants.	NOX and PM-10 emissions that vary as a function of the implied marginal plant heat rate, based on the market price forecast.
*	Updated CCGT cost and financing assumptions for calculating the long-run marginal cost.	CEC memo "Costs to Build and Operate a New Plant"	CEC Staff Report on comparative costs of generation technologies, 2003

Note: A larger number of asterisks indicates a greater level of change.

2.2 Report Organization

This report is organized into a chapter for each of the three energy sources. In each chapter, the complete derivation of the TDV values for each is provided. The process is broken down into steps, and each step is accompanied by a flow chart of the data required for that calculation, as well as an equation. The calculations are presented in order so that all of the inputs to a particular calculation are either direct inputs, or the result of previous calculations.

In addition to this manual, there is a set of spreadsheets that calculate the TDVs for each climate zone and energy type. The equations in this manual are identical to those used in the spreadsheet. The spreadsheet will be useful if you would like to recreate the values using different input data, look at how the calculation is made, or analyze the sensitivity of an input assumption to the final TDV values. Web links to the spreadsheets are provided in the report documenting the input data.

Finally, the indices used in the equations are the following:

y = year
z = climate zone
m = month
h = hour
c = customer class (residential and non-residential)

3 Electricity TDV Calculations

3.1 Wholesale Generation Capacity and Energy Values

This section describes the methodology used in calculating hourly wholesale generation capacity and energy values used in the electricity TDV calculations, including updates to more accurately reflect the value of demand response.

In development of the value of demand response (and in other proceedings), there is concern that the observed historical market price shapes from the 1998 and 1999 California Power Exchange (PX) that have been used for resource evaluation (both in the CEC TDV 2005 Update and the CPUC Avoided Costs, and in other proceedings) do not provide enough value in the high load hours to induce the entry of new generation capacity in the State.

To address this concern, we have developed a combustion-turbine (CT) peak adjustment to increase the value attributed to load reductions during the peak period, and correspondingly reduce the value of energy reductions in the off-peak period. In this way, the hourly avoided costs will provide full recovery of the all-in cost of a CT during the peak period, while at the same time providing full recovery (and no more) of the all-in cost of a combined-cycle gas turbine (CCGT) over the entire year.

A CT is used as the basis for the peak adjustment because it is a traditional capacity resource with well understood cost and performance that can be built as a ‘backstop’ measure to provide capacity to maintain reliability in the California control-area should it be needed. We note that it may be possible to purchase capacity for less in the emerging capacity markets in the State (for example from a CCGT), however, as a ‘backstop’ approach we feel that the CT represents a reasonable upper bound.

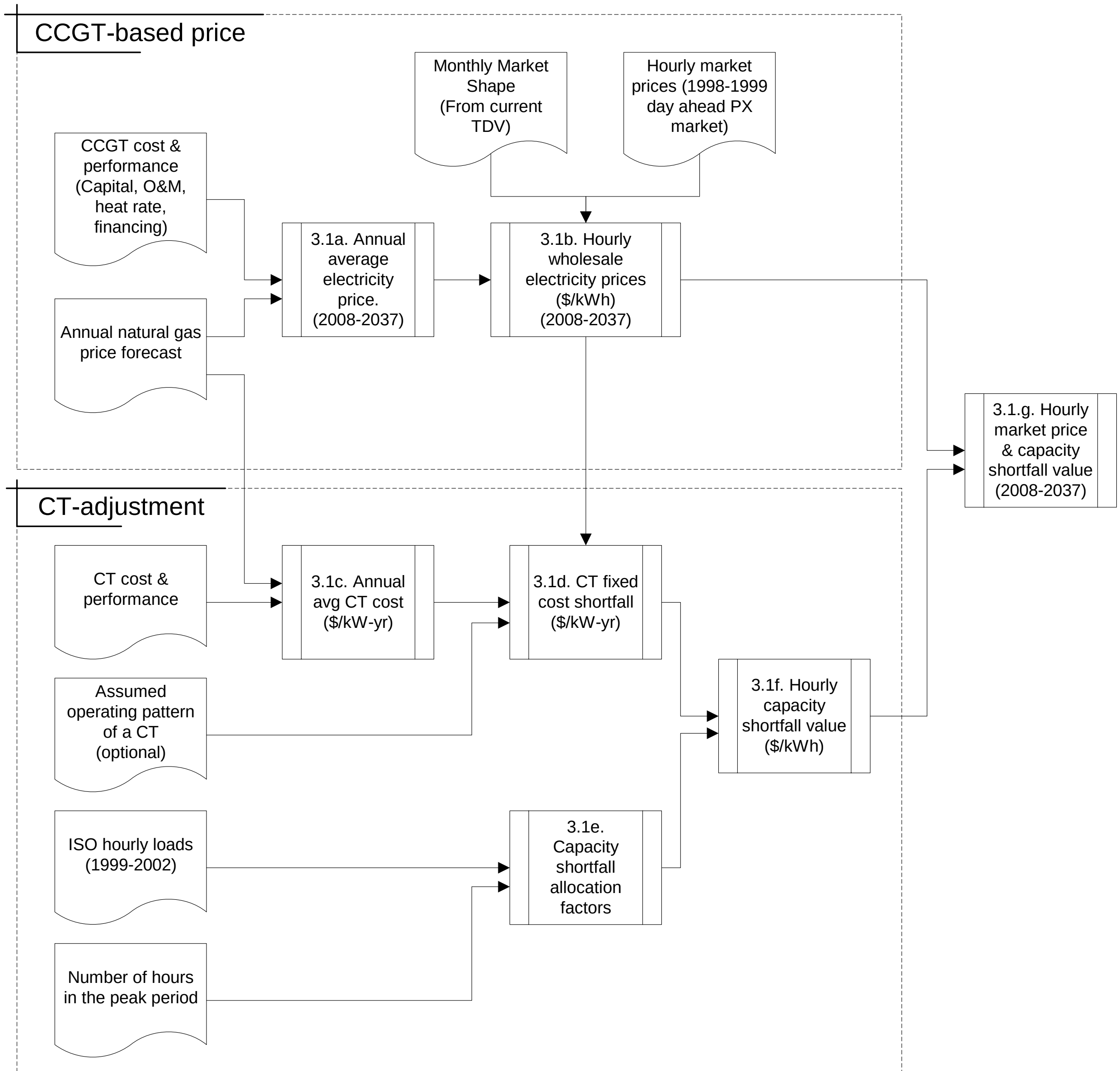
Figure 4 provides a graphic representation of the wholesale generation cost estimation process. The diagram can be divided into three main sections.

1 **CCGT-based price,** which is indicated by the large dashed rectangle at the top, shows the creation of an hourly generation market price forecast based on the cost of a CCGT. This section is consistent with the current CPUC Energy Efficiency avoided cost methodology as well as the current TDV methodology.

2 **CT-adjustment**, indicated by the large dashed rectangle at the bottom, shows the calculation of the CT peak adjustment.

3 **Total capacity and energy value.** This last step combines the CCGT-based prices and the CT-adjustment. The CT adjustment is added to the CCGT-based values during the peak period, and the off-peak period values are adjusted downward so that the annual average remains the same as for the original CCGT-based price.

Figure 4: Generation Cost Estimation Process



3.1.1 CCGT-based price

The next two equations detail the calculation of the CCGT-based hourly prices. As this methodology is consistent with both the current CPUC avoided cost methodology and the current TDV, the theoretical basis for the method will not be repeated herein.

Equation 3.1.a: Annual Average Long-run Generation Cost Forecast

$$AvgGen_{y,z} = \frac{FixedCapital_y * CRF + FixedO\&M_y}{8760 * CapacityFactor} + \left(Fuel_{y,z} * HeatRate\right) + VarO\&M_y$$

Unless otherwise noted, inputs for Equation 3.1.a are from the CPUC/CEC Market Price Referent proceeding.

Where

AvgGen	=	Average long-run generation cost of a CCGT ($/kWh)
FixedCapital	=	Present value installed cost of a new CCGT (expressed in $/kW), including financing costs, return on equity, return of investment, and accelerated depreciation tax effects. Assumed to escalate annually at the rate of inflation.
CRF	=	Capital Recovery Factor, which is constant in real dollars.
FixedO&M	=	Annual fixed O&M costs, expressed in $/kW-yr. Assumed to escalate annually at the rate of inflation.
CapacityFactor	=	% of hours in a year that CCGT would be expected to operate.
Fuel	=	Annual average natural gas price from CEC 2005 price forecast, differentiated by Northern and Southern California delivery areas.
HeatRate	=	Heat rate of the CCGT (BTU/kWh)
VarO&M	=	Variable operating and maintenance costs, excluding fuel costs. Assumed to escalate annually at the rate of inflation. ($/kWh)
Data Source:	=	CEC, Integrated Energy Policy Report (IEPR), 2005

Equation 3.1.b: Hourly CCGT-based generation prices

$$CCGT\_Gen_{y,h} = AvgGen_{y,z} * HourlyFactor_h$$

Where

CCGT_Gen	=	Hourly generation price, based on the long-run cost of a CCGT
AvgGen	=	Average annual price of the CCGT
HourlyFactor	=	Hourly electric generation price shape factor from 2005 TDV. This is the ratio of the average generation price for the hour divided by the average generation price for the year. Hourly market prices from the 1998 and 1999 day-ahead PX markets for NP-15 or SP-15.

3.1.2 CT Peak Adjustment

The CT peak adjustment is developed in three steps

1. **Determine the contribution to fixed costs needed to support the construction of a new CT.** This is the total revenue stream, above costs, that is required to provide a fair return on and of investment. We assume that the revenue stream will increase annually with inflation, so that on an annual basis, the required $/kW-yr contribution to fixed costs is calculated using the top equation shown below for *Equation 3.1.c: Annual Average CT Cost.* For 2008, this value is approximately $78/kW-yr.

2. **Determine the CT fixed cost shortfall.** Using the variable cost of a CT (calculated using the bottom equation in *Equation 3.1.c: Annual Average CT Cost.*) we then determine the contribution to fixed costs available from the market. The hourly market values are the CCGT-based prices from *Equation 3.1.b: Hourly CCGT-based generation* prices. The contribution to fixed costs is the positive difference between the hourly CCGT-based generation price and the variable cost of the CT. The CT fixed cost shortfall is the difference between the fixed cost of the CT ($/kW-yr) and the total hourly contributions to fixed costs.

2. **Allocate the CT fixed cost shortfall to hours.** The cost shortfall is assigned to hours in proportion to the criticalness of each hour. The higher the loading level, the higher the assumed need for capacity in that hour. The allocation factor reflects this relationship, and is similar in intent to traditional loss of load expectation analyses. See *Equation 3.1.e: Cost shortfall allocation factors.*

Equation 3.1.c: Annual Average CT Cost.

$$CTFixed_{y,z} = \left(FixedCapital_y * CRF\right) + FixedO\&M_y$$

and

$$CTVar_{y,z} = \left(Fuel_{y,z} * HeatRate\right) + VarO\&M_y$$

Where

CTFixed	=	Fixed cost of the simple cycle combustion turbine ($/kW-yr)
FixedCapital	=	Present value installed cost of a new combined cycle gas turbine (expressed in $/kW), including financing costs, return on equity, return of investment, and accellerated depreciation tax effects. Assumed to escalate annually at the rate of inflation.
CRF	=	Capital Recovery Factor, which is constant in real dollars.
FixedO&M	=	Annual fixed O&M costs, expressed in $/kW-yr. Assumed to escalate annually at the rate of inflation.
CTVar	=	Variable cost of the CT ($/kWh)
Fuel	=	Annual average natural gas price from CEC 2005 price forecast, differentiated by Northern and Southern California delivery areas.
HeatRate	=	Heat rate of the CCGT (BTU/kWh)
VarO&M	=	Variable operating and maintenance costs, excluding fuel costs. Assumed to escalate annually at the rate of inflation. ($/kWh)
Data Source	=	*CPUC/CEC Market Price Referent proceeding*

Equation 3.1.d: CT Fixed Cost Shortfall

$$CTShortfall_y = CTFixed_y - \sum_{h=1}^{PeakHours} Max(0, CCGT\_Gen_{y,h} - CTVar_h)$$

Where

CTShortfall	=	The difference between the fixed cost of a CT ($/kW-yr) and the contribution to fixed costs provided by the hourly electricity prices (CCGT_Gen). ($/kW-yr)

PeakHours = Number of hours in the peak period. The peak period can be defined as all hours where CCGT_Gen > CTVar, or a specified number of hours. The contribution to fixed cost calculation is performed with the hourly CCGT_Gen values sorted in descending order.

Equation 3.1.e: Cost shortfall allocation factors.

$$AllocShort_h = \frac{\dfrac{1}{(ResTarget - Load_h)}}{\sum_h^{AllocHours}\left[\dfrac{1}{(ResTarget - Load_h)}\right]}$$

Where

AllocShort = Allocation factor for the capacity shortfall. Allocation factor sums to 1.0. (%)

ResTarget = Target reserve margin target. This is the Peak ISO load for the year, plus 7% reserve margin, less 1000MW (representing the outage of one large generator) (MW)

Load = ISO load for the period corresponding to the market price shape (MarketPrice) used in developing the hourly generation prices (CCGT_Gen) (MW)

AllocHours = Number of the hours in the peak period defined for the purpose of allocating the capacity shortfall.

Equation 3.1.f: Hourly capacity shortfall value

$$CapShortfall_{y,h} = CTShortfall_y * AllocShort_h$$

3.1.3 Total wholesale energy and CT shortfall value

The generation value begins with the sum of the wholesale energy avoided cost and the allocated CT shortfall value. A simple summation, however, would result in overvaluation of baseload resources such as a CCGT. Therefore, the energy market prices in the non-peak hours are uniformly reduced by the same percentage to compensate for the addition of the CT shortfall value to the peak hours. This assures that the generation value reflects both the value of peaking capacity (the CT) and baseload resources (CCGT).

Equation 3.1.g: Hourly Market Price and CT Shortfall Value

For the peak hours:

$$TotGenCostHr_{y,h} = (CCGT\_Gen_{y,h} + CapShorfall_{y,h}) * (1 + Losses)$$

For the other, non-peak hours:

$$TotGenCostHr_{y,h} = CCGT\_Gen_{y,h} * \left[1 - \frac{CTShortfall_y}{\sum_{h'=1}^{Non-PeakHour} CCGT\_Gen_{y,h'}}\right] * (1 + Losses)$$

Where

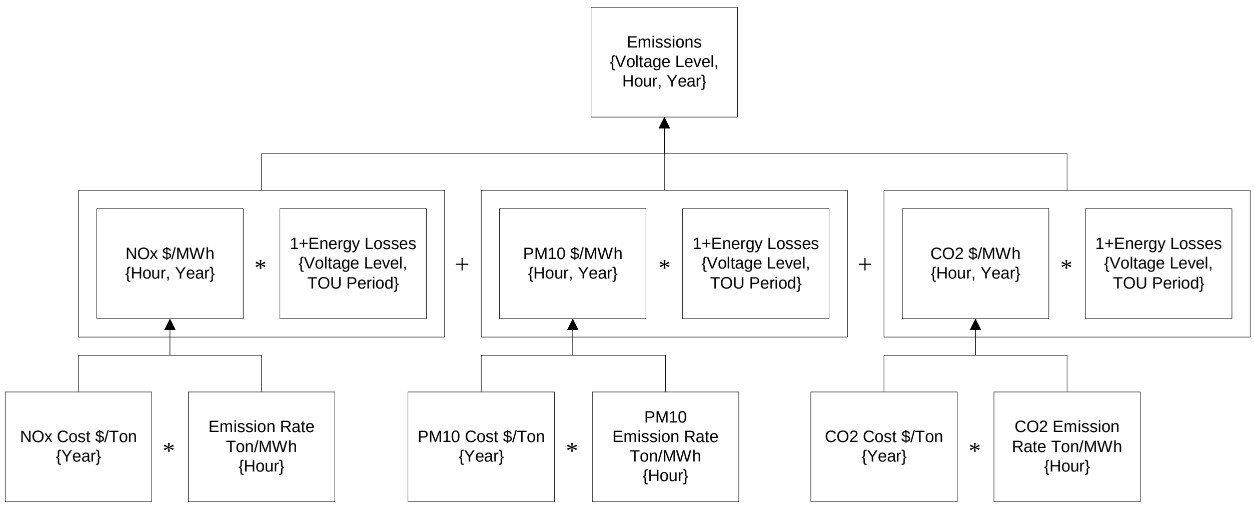
Peak Hours = Those that receive a non-zero allocation of the capacity shortfall. (see AllocHours)

h′	=	hours in the non-peak period
Non-PeakHours	=	Total number of hours in the non-peak period (8760 – AllocHours)
Losses	=	Percentage losses from the generation hub to the customer at the secondary service voltage level.

3.2 Emissions Costs

This section describes how emissions costs are calculated. The process is shown schematically in Figure 5 below.

Figure 5. Emmissions Costs Calculation Process



The approach used to calculate the environmental avoided cost streams is to multiply implied emissions rate of the marginal electricity generation plant by an average emissions price on a per pollutant basis. The key assumptions in the estimation of environmental avoided cost values included the following:

1. Focus on air emissions.
2. Assume gas-fired technologies are at the margin. This is consistent with the other elements of this avoided cost analysis.
3. Limit analysis to significant emissions. Assuming (1) and (2), the significant emissions that we have included in this analysis are oxides of nitrogen (NOx), particulate matter less than 10 µm (PM-10), and carbon dioxide (CO_2).

The estimation of emission costs follows the methodology detailed in *Methodology and Forecast of Long Term Avoided Costs for the Evaluation of California Energy Efficiency Programs*, October 2004.

In order to apply the emissions costs by hour for the TDV values, an implied marginal heat rate in each hour is estimated based on the market price in each hour. The implied heat rate represents the theoretical efficiency of the last plant dispatched in each hour. This is the plant that would have its output reduced first if load were to be decreased. The implied heat rate is the generation market price divided by the cost of fuel. The following two equations show how the implied heat rate determines the hourly emission rates.

Equation 3.2.a: CO2 Emissions by Year and Hour

$$Emissions[CO2]_{y,h} = CI * \mathrm{Im}\ pliedHeatRate_{y,h}$$

Where

Emissions[CO2]	=	Rate of emissions of CO2 in lbs/kWh
CI	=	Carbon intensity of natural gas (117lb CO2/MMBTU)
ImpliedHeatRate	=	Implied heat rate for each hour. This is the generation market price for each hour (Equation 3.1.b) divided by the annual natural gas price (adjusted for compression, losses and unaccounted for). Constrained to lie within a 14,000 and 6,240 BTU/kWh heat rate range. (BTU/kWh)

Using the NOx emission rates reported for existing, new, and proposed natural gas-fired combined cycle and simple cycle plants located in California, we were able to obtain a relevant range of emission rates to include in our analysis. As NOx emissions vary as a direct result of the installed abatement technology, it is difficult to determine a specific emission rate that would be representative of a typical plant in a particular hour. While there is plant-specific variation in the emission rates, however, average rates relative to heat rate can be calculated with reasonable accuracy. There is a clear difference between emission rates of higher efficiency plants versus lower efficiency plants. This is likely due to the often prohibitive expense of retrofitting older, and often less efficient plants, with best available control technologies (BACT), resulting in emission rates that meet area regulations but are no lower than required. To reflect this variation in emission rates, we used the emission rates for representative high and low efficiency units, and then applied a straight-line interpolation for plant efficiencies between those units. We also constrained the emission rates for all hours to lie at or between the two "bookend" plants. The emission rates for the bookend plants are shown in Table 3 and the equation for estimating NOx and PM-10 emission rates is shown as Equation 3.2.b.

Table 3: Emission Rates for High and Low Efficiency Plants

	Heat Rate	NOx (lbs/MWh)	PM10 (lbs / MWh)	CO2 (tons/MWh)
Low Efficiency Plant	14000	0.27463	0.09850	0.81900
High Efficiency Plant	6240	0.05412	0.05250	0.36500

Equation 3.2.b: NOX and PM-10 Emission as a Function of Implied Heat Rate

$$Emissions[X]_{y,h} = EmRate[X, High] + (ImpliedHeatRate_{y,h} - HeatRate[High]) * EmissionSlope[X]$$

Where

Emissions[X]	=	Rate of emissions in lbs/kWh for each year and hour
X	=	NO_X or PM-10
EmRate[X,High]	=	Emission rate of the high efficiency (low emission) unit. (lb/kWh)
HeatRate[High]	=	Heat rate of the high efficiency (low emission) unit. (BTU/kWh)

EmissionSlope[X] = Functional relationship between unit heat rates and emission levels. Based on a linear interpolation between the high and low efficiency plant shown in Figure 3. Once the emission rates are calculated, it is a simple process to multiply those emission rates by a cost for those emissions to arrive at hourly emission costs. Those hourly emission costs are then increased to reflect energy losses during the transmission and distribution of the electricity.

Equation 3.2.c: Emission Costs by Year and Hour

$$EmissionCostHr[X]_{y,h} = Emissions[X]_{y,h} * EUnitCost[X] * (1 + Losses)$$

Where

EmissionCost[X] = Cost of emissions ($/kWh).

X	=	CO2, NOX, or PM-10
EUnitCost[X]	=	Emission unit cost of X in $/lb
Losses	=	Percentage electricity transmission and distribution losses from the generator to the customer at the secondary voltage level

Equation 3.2.d: Present Value of Emission Costs for Each Hour

$$PV\_TOT\_Emission_h = \sum_{y=1}^{15/30} \frac{EmissionCostHr[CO2]_{y,h}}{(1+r)^y} + \sum_{y=1}^{15/30} \frac{EmissionCostHr[NOX]_{y,h}}{(1+r)^y} + \sum_{y=1}^{15/30} \frac{EmissionCostHr[PM-10]_{y,h}}{(1+r)^y}$$

Where

PV_TOT_Emmision	=	The present value of emission costs for all emissions over either 15 or 30 years
r	=	Discount rate

Equation 3.2.e: Weighted Average Environmental Adder

$$WtdAvgEmission_{c,z} = \sum_{h=1}^{8760} PV\_TOT\_Emission_h \times Class\,Shape_{h,c,z}$$

With the emissions costs calculated and the index determined, the weighted average emissions costs for residential and non-residential load profiles are calculated.

Where

ClassShape	=	Class load shape, the load in every hour of the year as a percentage of annual average load, for residential and non-residential customers

- The hourly residential and nonresidential load shapes for each utility are from the statistical load profiles provided for settlement on each utility's website.
- The timing of the weekends and holidays in the 8760 stream are aligned based on the current nonresidential Title 24 ACM standard (year 1991 day order).

3.2.1 Generation Ancillary Services

Ancillary services are modeled as a uniform percentage of the energy market price (*Equation 3.1.b: Hourly CCGT-based generation prices*). This is based on the finding in the CPUC avoided cost proceeding that ancillary services are roughly proportional to market prices (based on this proceeding, ancillary services are 2.8% of the market price).

Equation 3.2.f: Ancillary Service Costs

$$AncillaryCostHr_{y,h} = CCGT\_Gen_{y,h} * ASPercent * (1 + Losses)$$

Where

CCGT_Gen	=	Hourly generation market price forecast, based on the all-in cost of CCGT

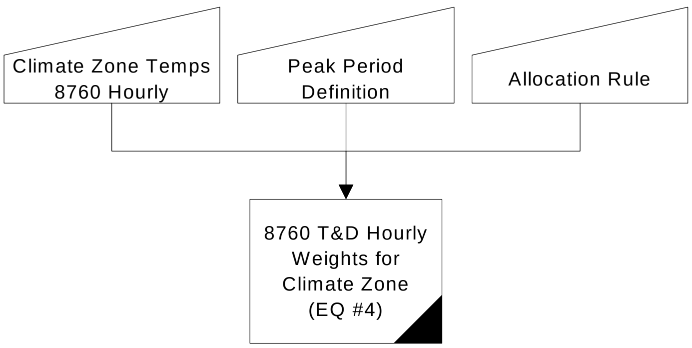
ASPercent = Proportion of ancillary services costs relative to market price in each hour

Losses = Average losses from the generation market hub to the customer meter.

3.3 Transmission and Distribution

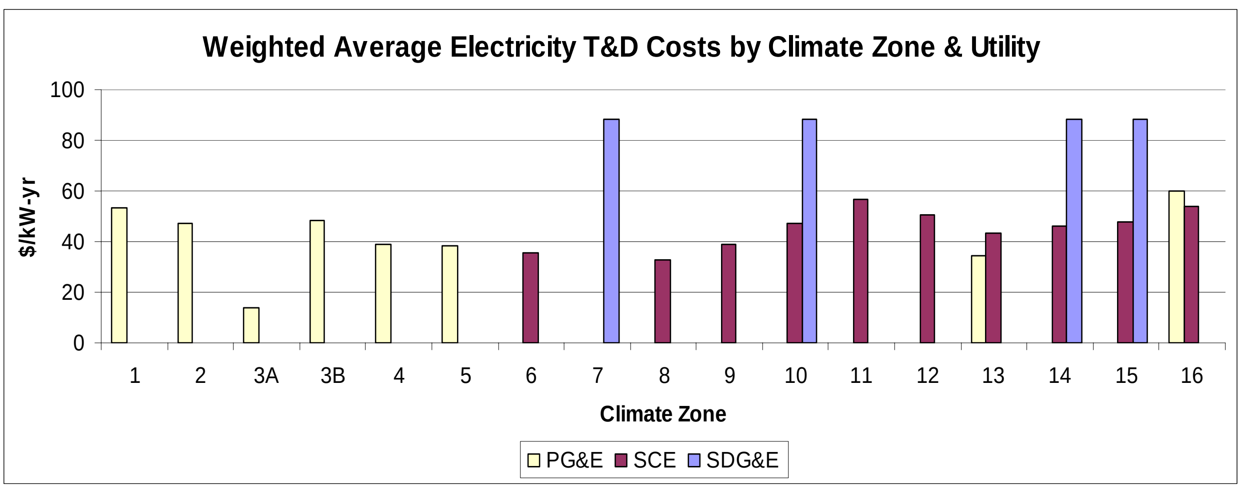
3.3.1 Capacity Costs

Figure 6. T & D capacity cost calculation process



T&D capacity costs are from the CPUC energy efficiency avoided cost report. The costs vary by area for PG&E and SCE. The CPUC avoided T&D capacity costs are shown in the figure below. For PG&E and SCE, the climate zone costs are weighted averages based on the peak demands for each planning area within the climate zone.

Figure 7: Electric T&D avoided costs by climate zone.



Note: Climate Zone 3A includes San Francisco, East Bay, and Peninsula sub-areas, while 3B includes portions of Central Coast, Mission, and North Bay.

3.3.2 Allocation of T&D Capacity Costs

The 8760 T&D hourly weights are calculated based on the hourly temperature profile for each climate zone based on the Typical Meteorological Year (TMY) data using the same approach as was used in the 2005 TDV update. The same weather data is used in the building simulation models so that the highest costs will be aligned with the times when buildings use the most heating and cooling. Only non-holiday weekdays as defined by the non-residential

ACM manual are included as potential days for peak electric loads. Each set of weights is calculated in a separate spreadsheet and linked into TDV calculation spreadsheet.

Summer peak hours are then identified based on hourly temperature for each climate zone. Weights are then calculated proportional to how high temperatures are in the summer. The same allocation rule is used in each climate zone, however, the profile is different for each climate.

To calculate the summer T&D weights the following process is used.

1. The non-holiday weekdays are identified based on the non-residential ACM standard for building schedules.

2. The highest temperature of the 8760 TMY data-set occurring on a non-holiday weekday is identified.

3. Weights are allocated to the hours within 15 degrees of the peak temperature. The highest temperature hour gets the most weight, and the hours with temperature 15 degrees below peak get the least weight. The distribution of weights is based on a triangular weighting approach. Hours with temperatures below 15 degrees of the peak temperature do not get any weight.

This process has been carefully considered and yields results very close to a more detailed approach used by PG&E that relies on hourly load information. In areas with extreme weather, this process yields high weights to the few highest temperature hours of the year. In areas with mild weather, this process yields low weights to a large number of hours.

Equation 3.3.a: Hourly T&D Capacity Cost

$$T\ \&\ DCostHr_{y,h,z} = T\ \&\ DCapCost_{y,z} * TempAlloc_h * (1 + T\ \&\ DLosses)$$

Where

T&DCostHr	=	Hourly T&D avoided capacity cost ($/kWh)
T&DCapCost	=	T&D avoided capacity cost for climate zone z, in year y
TempAlloc	=	Hourly allocation factor for climate zone z, based on temperatures. Allocation factors for a climate zone sum to 1.0.
T&DLosses	=	Loss factor from the customer meter up to the T&D equipment (e.g.: secondary to primary for substations, secondary to transmission for high voltage circuits)

Data Sources:

Climate Zone Temperatures (8760): Specific references for the Climate Zone Temperature input data can be found in the CEC Report #P400-92-004 "2001 Energy Efficiency Standards for Residential and Nonresidential Buildings," June 1, 2001 posting at the following website:

http://38.144.192.166/title24/standards/2001-10-04_400-01-024.PDF.

3.4 Value of Avoided Customer Outages

Demand response programs that can be operated during emergency ‘rotating black-out’ conditions offer the ability to avoid customer outages. To evaluate this type of program, the methodology assumes that the DR load reduction (or partial outage) will take the place of a full customer outage. However, the avoided outage value is not additive with the market and capacity values discussed above. The load reduction of a DR event can provide either market and capacity benefits, or it can provide emergency (outage avoidance) value, but not both.

The value of avoided customer outages is based on customer value of service (VOS) studies. VOS estimates can vary widely between and within classes of customers. VOS estimates can also vary depending on the season, duration of the outage, timing, and amount of notice provided before the outage. For evaluation purposes, we use a class annual sales weighted VOS value. The system average appropriately reflects the likelihood of any customer being subjected to a supply or capacity related outage[2]. All customers, excluding those on circuits that serve exempt loads such as emergency service facilities or crucial medical loads, are assigned to rotating outage blocks. Therefore all non-exempt customers have an equal likelihood of being interrupted during a supply or capacity related outage.

A link to the spreadsheet and data sources for the VOS values used here is provided in the input data report.

3.5 Customer Impacts from Demand Response Participation

Demand response differs significantly from the traditional design decisions and energy efficiency measures considered in Title 24 energy usage evaluations. Title 24 traditionally considers the question of how much energy is needed to provide the same comfort and lighting levels under different design and device configurations. DR, however, does not maintain comfort and lighting levels. Rather, DR will likely degrade comfort and/or lighting levels for a short period of time.

3.5.1 Customer Impact for Voluntary Programs

For voluntary DR programs, we set the customer cost equal to ½ of the difference between the DR rate or incentive payment received by the customer, and their normal electricity rate. This is based on the assumption that customers will use electricity to the point where their marginal value from the use of electricity is equal to the cost of the electricity (or their marginal loss for reducing usage is equal to the DR incentive payment). If the customer's demand curve is linear over the region between the original electricity price and the price (or incentive) during the DR event, then the "1/2 rule" reflects the customer's average value over the range of reduced electricity usage.

Equation 3.5.a: Customer Comfort Impact for Voluntary DR Programs

$$ComfortLoss_{p,c} = \tfrac{1}{2} * \left(DRPrice_{i,c} - Rate_{i,c}\right)$$

Where

ComfortLoss	=	Cost imposed on customer from DR operation ($/kWh)
DRPrice	=	Price signal during DR event, or DR incentive payment expressed in $/kWh.
Rate	=	Marginal customer price, absent the DR event. ($/kWh)
p	=	DR program for customer class c.

3.5.2 Customer Impact for Non-Overrideable Programs

The impact on customers is evaluated differently for mandatory or non-overrideable programs because the impact on customers is likely higher than when the customer has the option to participate. The societal justification for this non-overrideable event is that one trades off full outages (customer interruptions) with partial outages (demand response). The benefit of this tradeoff arises from the fact that full outages impose a higher welfare loss upon customers than partial outages.

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[2] The methodology does not consider reductions in distribution-related outages (car hits a pole, tree falls into a circuit, animal-caused outage, etc.).

Unfortunately, given that there is no incentive payment, we cannot apply *Equation 3.5.a: Customer Comfort Impact for Voluntary DR Programs* to the calculation of partial outage costs. Instead we look to partial outage cost surveys which are not as numerous as full outage VOS studies. The partial outage cost values and data sources used in this survey are provided in input data appendix.

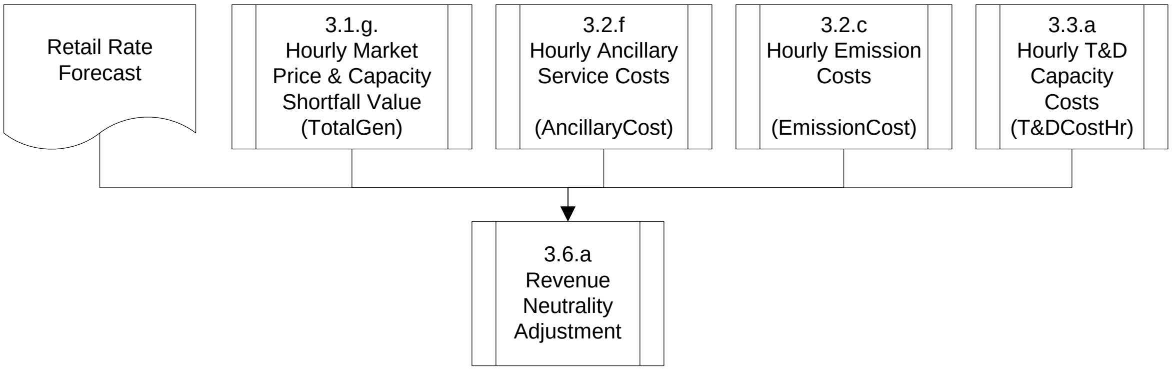
3.6 Revenue Neutrality Adjustment

A revenue neutrality adder is estimated so that the load weighted average of the T&D, generation, and revenue neutrality adder results in forecast retail rates for each class.

<u>*Retail Rate Forecast*</u>

Figure 8 shows the revenue neutrality adjustment calculation process, which uses the electricity retail rate forecasts from the CEC.

Figure 8. Revenue neutrality adjustment calculation process



The revenue neutrality adjustment is calculated as the difference between the retail rate forecast and the class weighted average generation, ancillary service, emission and T&D costs, as shown in Equation 3.6.a.

Equation 3.6.a Revenue neutrality adjustment

$$\mathrm{Re}\,vNeutrality_p = LevelRate_p - \sum_h \left(LevelGenCost_p - LevelAncillaryCost_p - LevelEmissionCost_p - LevelT\,\&\,DCost_p\right) * ClassSh$$

Where

LevelRate	=	Levelized rate level by year (CEC forecast of average annual rate levels)
LevelGenCost	=	Levelized generation (energy market & capacity shortfall) *(Equation 3.1.g)* at secondary voltage
LevelAncillaryCost	=	Levelized ancillary service cost *(Equation 3.2.f)* at secondary voltage
LevelEmissionCost	=	Levelized emission cost *(Equation 3.2.c)* at secondary voltage
LevelT&DCost	=	Levelized T&D cost *(Equation 3.3.a)* at secondary voltage

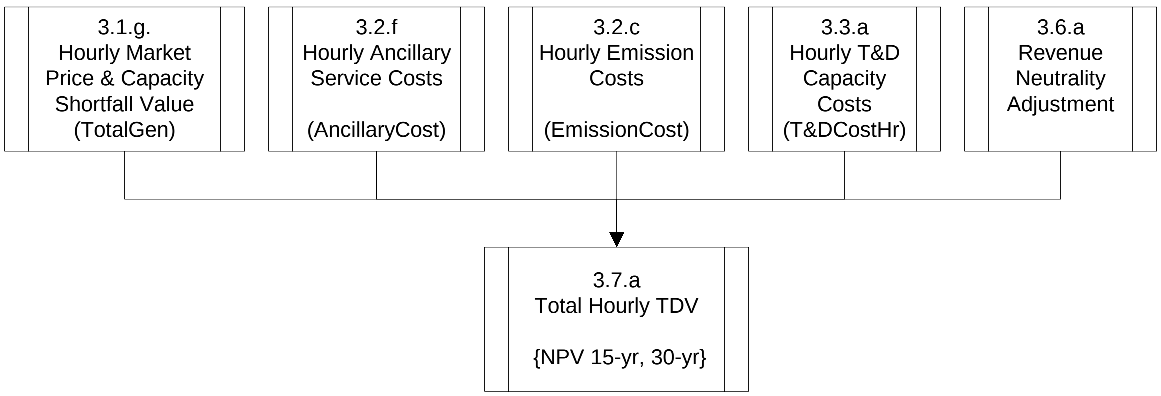
For the levelization, the stream of values is first converted to a present value using the social nominal discount rate of 3 %, over the period (p) of 15 or 30 years. The present value is then converted to levelized annual values using the same period p and the real discount rate. An example using Emission Cost is shown below.

Data Source: California Energy Commission Monthly Retail Forecast

3.7 Total Hourly TDV Value

The final step in the process is to estimate the hourly generation, emissions, and T&D lifecycle costs, add the retail rate and the existing standard adder to derive the hourly TDV values. This process is shown schematically in Figure 9.

Figure 9 Process for calculating total hourly TDV value



The calculation method is shown in Equation 3.7.a.

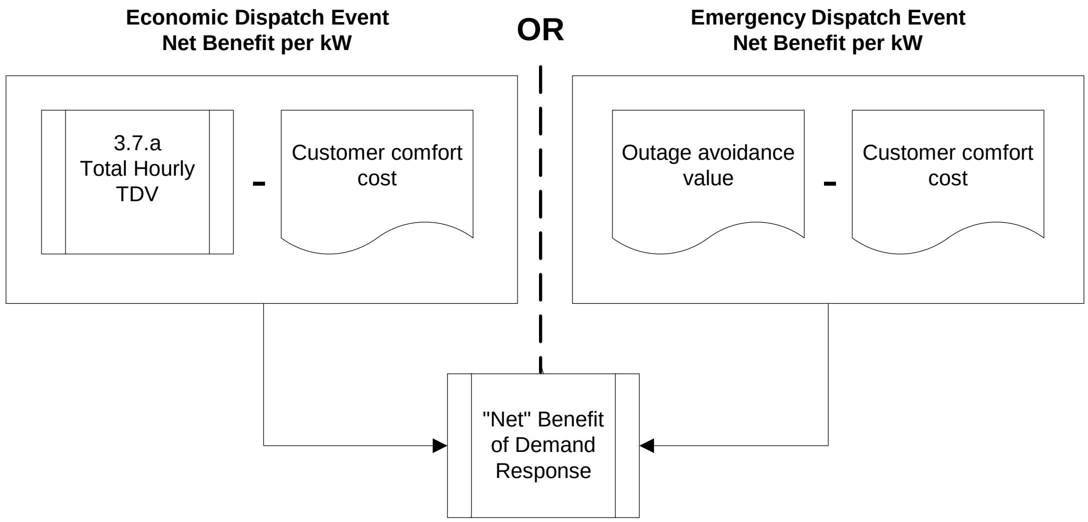
Equation 3.7.a: Total Hourly TDV (NPV 15-Year, 30-Year)

$$\mathrm{T}DV\mathrm{h,c,z} = \sum_{y=1}^{15/30}\left[\begin{pmatrix} \mathrm{RevNeutrality}_{\mathrm{c,z}} + \\ \mathrm{TotEmissionHr}_{\mathrm{h,c,z}} + \\ \mathrm{T}otGenCostHr_{\mathrm{h,c,z}} + \\ \mathrm{T}\ \&\ DCostHr_{\mathrm{h,c,z}} + \\ AncillaryCostHr_{\mathrm{h,c,z}} \end{pmatrix} * \frac{1}{(1+r)^{y}}\right]$$

3.8 Demand Response Value

As discussed in section 3.4, demand response events can avoid high procurement costs or reduce customer outages. The avoidance of high procurements costs is shown on the left portion of Figure 10. The hourly TDV values developed above are used to determine the demand response events. Each demand response event avoids the corresponding hourly TDV values, while imposing a comfort or productivity cost upon the DR participant. The TDV value less the comfort cost is the “net” benefit of the economic demand response event. For the emergency response event, shown on the right side of the figure, the “net” benefit is the value of avoiding outages less the comfort cost. The duration of emergency events are determined exogenously. Currently a value of 2.4 hours per year, corresponding to a one day in ten years LOLE, is assumed for the emergency events. As discussed in Section 3.4, a given kW provides an emergency benefit when dispatched for emergency events, or an economic benefit when dispatched for economic events, but cannot provide both benefits at the same time.

Figure 10: Demand Response Value

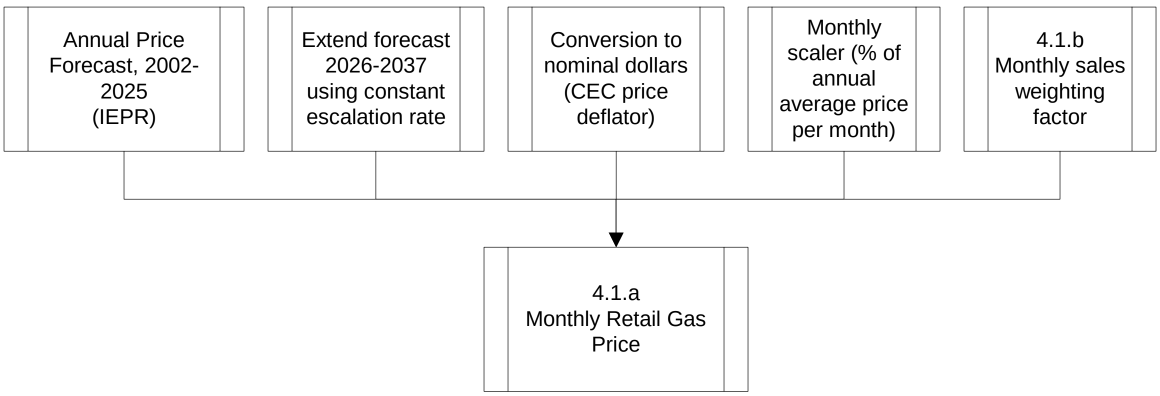


4 Natural Gas TDV Calculations

4.1 Natural Gas Retail Price Forecast

The CEC's IEPR provides annual retail price forecasts for natural gas in the years 2008 through 2025. This forecast is extended from 2026 through 2037 using a constant escalation rate based on the average rate from 2020 through 2025. The methodology for obtaining monthly gas price forecasts is shown schematically in Figure 11.

Figure 11: Monthly Retail Price Forecast for Natural Gas



The calculation of monthly natural gas price forecasts is shown in the equations below.

Equation 4.1.a: Monthly Retail Natural Gas Price

$$\text{Monthly Retail Gas Price}\left(\frac{\$}{MMBtu}\right)_{m,y,z} = \frac{NPV(AnnualGas\Pr ice)_{15/30} * \%\Pr iceMonthly}{WeightedAvgFactor}$$

Where

%PriceMonthly = Monthly price as a percentage of annual average price

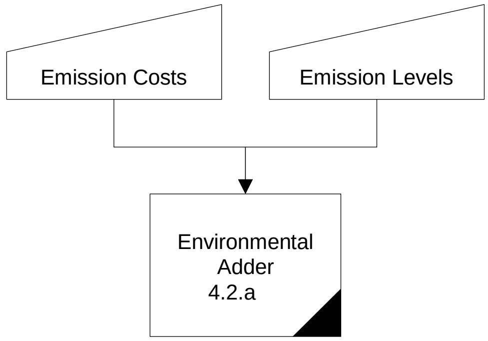
Equation 4.1.b: Monthly Weighted Average Factor

$$WeightedAvgFactor = \sum_{m} \%SalesMonthly * \%\Pr iceMontly$$

Where

%SalesMonthly = Monthly sales as a percentage of annual average sales

4.2 Natural Gas Emissions Costs



Equation 4.2.a: Environmental Adder

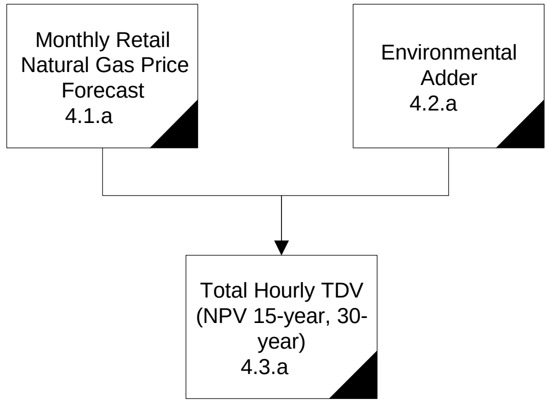
$$Environmental\ Adder\left(\frac{\$}{MMBtu}\right) = \sum_{y=1}^{15/30} \frac{Emission\ Cost\left(\frac{\$}{ton}\right) \times Emission\ Level\left(\frac{tons}{MMBtu}\right)}{\left[1+r\right]^{y}}$$

The environmental adder for natural gas does not vary in time like the environmental adder for electricity. The same amount of pollutants are emitted from the combustion of natural gas regardless of the time of year. The environmental adder is calculated by multiplying the amount of emissions by the price of emissions.

4.3 Natural Gas TDV Values

The monthly retail natural gas price and the environmental adder are combined to calculate the natural gas TDV values, as shown in Figure 12.

Figure 12. Natural Gas TDV Value Calculation



Equation 4.3.a: Total Hourly TDV (NPV 15-Year, 30-Year)

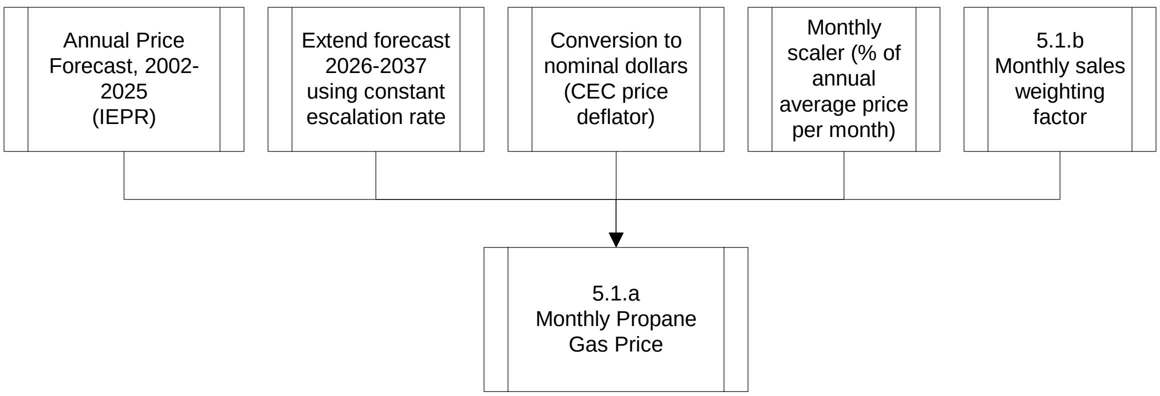
$$\text{TDV Values}\left(\frac{\$}{MMBtu}\right)_{m,z,c} = \begin{matrix} \text{Monthly Retail Gas Price}\left(\frac{\$}{MMBtu}\right)_{m,z} + \\ \text{Environmental Adder}\left(\frac{\$}{MMBtu}\right) \end{matrix}$$

5 Propane TDV Calculations

5.1 Propane Retail Price Forecast

The US Department of Energy Energy Information Agency (DOE EIA) provides annual retail price forecasts for propane in the years 2008 through 2025. This forecast is extended from 2026 through 2037 using a constant escalation rate based on the average rate from 2020 through 2025. The methodology for obtaining monthly gas price forecasts is shown schematically in Figure 13.

Figure 13: Monthly Retail Price Forecast for Propane



The calculation of monthly propane price forecasts is shown in the equations below.

Equation 5.1.a: Monthly Retail Propane Price

$$\text{Monthly Retail Gas Price}\left(\frac{\$}{MMBtu}\right)_{m,y,z} = \frac{NPV(AnnualGas\,\mathrm{Pr}\,ice)_{15/30} * \%\,\mathrm{Pr}\,iceMonthly}{WeightedAvgFactor}$$

Where

%PriceMonthly = Monthly price as a percentage of annual average price

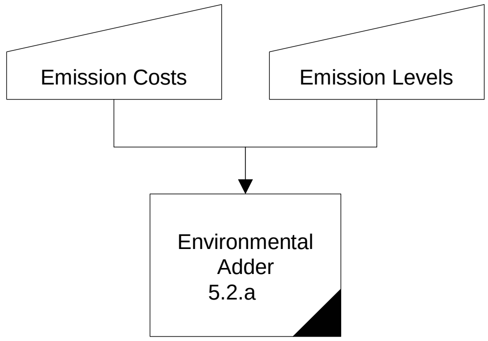
Equation 5.1.b: Monthly Weighted Average Factor

$$WeightedAvgFactor = \sum_{m} \%SalesMonthly * \%\,\mathrm{Pr}\,iceMontly$$

Where

%SalesMonthly = Monthly sales as a percentage of annual average sales

5.2 Propane Emissions Costs



Equation 5.2.a: Environmental Adder

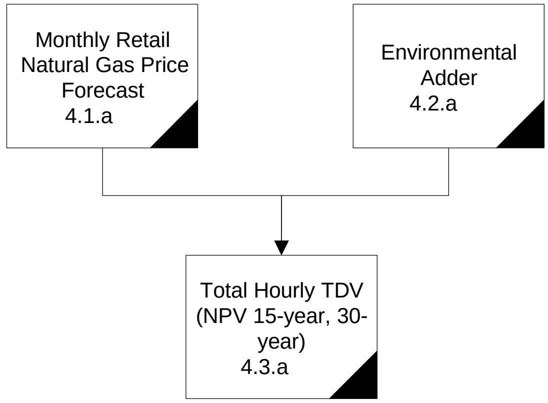
$$Environmental\ Adder\left(\frac{\$}{MMBtu}\right) = \sum_{y=1}^{15/30} \frac{Emission\ Cost\left(\frac{\$}{ton}\right) \times Emission\ Level\left(\frac{tons}{MMBtu}\right)}{[1+r]^{y}}$$

The environmental adder for propane does not vary in time like the environmental adder for electricity. The same amount of pollutants are emitted from the combustion of propane regardless of the time of year. The environmental adder is calculated by multiplying the amount of emissions by the price of emissions.

5.3 Propane TDV Values

The monthly retail propane price and the environmental adder are combined to calculate the propane TDV values, as shown in Figure 14. Propane TDV Value Calculation.

Figure 14. Propane TDV Value Calculation



Equation 5.3.a: Total Hourly TDV (NPV 15-Year, 30-Year)

$$\text{TDV Values}\left(\frac{\$}{MMBtu}\right)_{m,z,c} = \begin{array}{c}\text{Monthly Retail Gas Price}\left(\frac{\$}{MMBtu}\right)_{m,z} + \\ \text{Environmental Adder}\left(\frac{\$}{MMBtu}\right)\end{array}$$