California PATHWAYS Model Framework and Methods

DRAFT: June 5, 2015

Model version: 2.3

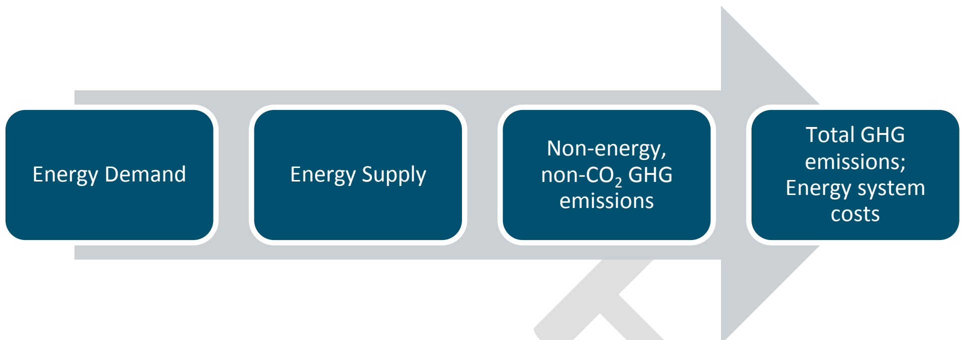
Table of Contents

1 Model Overview

PATHWAYS is a long-horizon energy model developed by Energy and Environmental Economics, Inc. (E3) that can be used to assess the cost and greenhouse gas emissions impacts of California's energy demand and supply choices. The model can contextualize the impacts of different individual energy choices on energy supply systems (electricity grid, gas pipeline) and energy demand sectors (residential, commercial, industrial) as well as examine the combined impact of disparate strategies designed to achieve deep de-carbonization targets. This document provides an overview of the California PATHWAYS modeling framework and methodology, and documents key data input sources. This section describes the basic modeling framework utilized in PATHWAYS to synthesize energy demand and energy supply options to calculate greenhouse gas (GHG) emissions and energy system costs for each scenario.

This methodology report is structured around the key elements of the PATHWAYS model as illustrated in Figure 1. Section 2 describes energy demand sectors and sources of energy demand data, Section 3 describes energy supply infrastructure and fuel types and Section 4 discusses non-energy, non-CO2 greenhouse gas emissions.

Figure 1. Basic model framework



1. **Energy Demand:** projection of energy demand for ten final energy types. Projected using an activity-based approach, with a stock-rollover accounting of the stock of energy end-use technologies in most sectors.

2. **Energy Supply:** informed by energy demand projections. Final energy supply can be provided by either fossil fuel primary energy types (oil; natural gas; coal) or by decarbonized sources and processes (renewable electricity generation; biomass conversion processes; carbon capture and sequestration). The energy supply module projects costs and GHG emissions of all energy types.

3. **Non-energy, non-CO_2 GHG emissions:** Examples of non-energy GHG emissions include methane and N_2O emissions from agriculture and waste, refrigerant F-gases, and emissions from cement production. Non-energy GHG emissions are estimated for Reference and low-carbon scenarios based on estimates of emission reduction potential.

4. **Summary Outputs:** Calculation of total GHG emissions and energy-system costs (end-use stocks as well as energy costs). These summary outputs are used to compare economic and environmental impacts of scenarios.

PATHWAYS projects energy demand in eight demand sectors shown in Table 1.

Table 1 PATHWAYS Demand Sectors

Sector	
Residential	Petroleum Refining
Commercial	Agriculture
Industrial	Water-Energy and Transportation, Communication, and Utilities (TCU)
Transportation	Oil & Gas Extraction

For those sectors that can be represented at the stock level – residential, commercial, and transportation – PATHWAYS models a stock rollover of technologies by vintage for individual subsector (i.e. air conditioners, light duty vehicles, etc.). For all other sectors, PATHWAYS utilizes a regression approach to project energy demand out to 2050. These two approaches are utilized to project ten final energy supply types (Table 2).

Table 2 PATHWAYS Final Energy Types

Final Energy	
Electricity	Gasoline
Pipeline Gas	Liquid Petroleum Gas (LPG)

Final Energy	
Compressed Pipeline Gas	Refinery and Process Gas
Liquefied Pipeline Gas	Coke
Diesel	Waste Heat

These final energy types can be supplied by a variety of different resources. For example, pipeline gas can be supplied with natural gas, biogas, hydrogen, and/or synthetic natural gas (produced through power-to-gas processes). These supply composition choices affect the cost and emissions profile of each final energy type. Likewise, gasoline can be supplied with fossil gasoline or renewable gasoline; diesel can be supplied with fossil gasoline or renewable diesel; electricity can be supplied with natural gas, coal, hydroelectric power, renewable power, etc.

2 Final Energy Demand Projections

2.1 Overview

The basic stock roll-over methodology is used both in the development of the demand unit projections as well as the supply unit stock analysis. For example, PATHWAYS uses a stock roll-over function to project square feet of indoor space and uses a stock roll-over function to estimate the stock efficiency of air conditioners used to cool that indoor space. The basic mechanics of stock roll-over are used throughout the model in estimating basic energy service demands, calculating current and future baseline stock efficiencies, and calculating the impacts of our mitigation measures. The stock roll-over modeling approach necessitates inputs concerning the initial composition of equipment (vintage, fuel type, historical efficiencies, etc.) as well as estimates of the useful lives of each type of equipment.

Stock roll-over functions are determined by technology useful lives, scenario-defined sales penetration rates, and the shapes of those sales penetrations (S-curves that might more closely mirror market adoption; and linear adoptions that may more accurately reflect policy instruments). Given that the model is designed to provide information on the technologies necessary to reach long-term carbon goals, these adoption rate input assumptions are not forecasts:

they are not dynamically adjusted to reflect consumer preference, energy costs, payback periods, etc. which might inform technological adoption rates in practice. PATHWAYS models a stock roll-over at the technology level for a limited set of subsectors in which homogeneous supply units could be determined (i.e. residential water heating).

2.2 Residential

PATHWAYS' Residential Module is used to project residential final energy consumption, CO_2 emissions, and end-use equipment costs by census region and year for the 12 end uses shown in Table 3. The first 11 end uses are represented at a technology level, while the "Other" subsector is represented on an aggregate basis.[1]

Table 3. Residential end uses and model identifiers

Subsector		Model Identifier
1.	Water Heating	RES_WH
2.	Space Heating	RES_SH
3.	Central Air Conditioning	RES_CA
4.	Room Air Conditioning	RES_RA
5.	Lighting	RES_LT

[1] "Other" includes ceiling fans, coffee machines, dehumidifiers, DVD players, external power supplies, furnace fans, home audio equipment, microwaves, personal computers, rechargeable devices, security systems, set-top boxes, spas, televisions, and video game consoles.

	Subsector	Model Identifier
6.	Clothes Washing	RES_CW
7.	Clothes Drying	RES_CD
8.	Dishwashing	RES_DW
9.	Cooking	RES_CK
10.	Refrigeration	RES_RF
11.	Freezer	RES_FR
12.	Other	RES_OT

Changes in final energy consumption, CO_2 emissions, and end use equipment costs in the Residential Module are driven by changes to the stock of buildings and energy end use equipment, which grow, rollover (retire), and are replaced over time. Stock growth and replacement — new stock — provides an opportunity for efficiency improvements in buildings and equipment, and for fuel switching through changes in equipment. Users reduce residential CO_2 emissions in PATHWAYS by implementing measures that change the building and equipment stock over time.

This section provides an overview of the mechanics of the stock-rollover process at the heart of the Residential Sector Module (Section 2.2.1), and describes methods for calculating final energy consumption (Section 2.2.2), CO_2 emissions (Section 2.2.3), and energy system costs (Section 2.2.4). The section closes with a list of data inputs and sources (Section 2.2.5).

2.2.1 RESIDENTIAL STOCK-ROLLOVER MECHANICS

The Residential Module includes a stock-rollover mechanism that governs changes in residential building stock composition, floor area, building shell efficiency, end use equipment efficiency, fuel switching opportunities, and equipment cost over time. The mechanism tracks building and equipment vintage — the year in which a building was constructed or a piece of equipment purchased — by census region and housing type.

At the end of each year, PATHWAYS retires or renovates some amount of a given housing or equipment type in a given region ($S.RET_y$), by multiplying the initial stock of each vintage (S_{vy}) by a replacement coefficient (β_{vy}).

Equation 1

$$S.RET_y = \sum_{v}^{y} S_{vy} \times \beta_{vy}$$

New Subscripts

y	year	is the model year (2010 to 2050)
v	vintage	is the building or equipment vintage (1950 to year y)

New Variables

$S.RET_y$	is the amount of existing stock of buildings or equipment retired or renovated in year y
$S.EXT_{vy}$	is the existing stock of buildings or equipment with vintage v in year y
β_{vy}	is a replacement coefficient for vintage v in year y

The replacement coefficients are generated by a survival function that uses Poisson distribution, with a mean (λ) equal to the expected useful life of the building or equipment.

Equation 2

$$\beta_{vy} = e^{-\lambda} \frac{\lambda^{y-v+1}}{(y-v+1)!}$$

We use the Poisson distribution as an approximation to the survival functions in the NEMS Residential Demand Module, which are based on a Weibull distribution fitted to the linear survival functions historically used in NEMS.[2] The Poisson distribution has a right-skewed density function, which becomes more bell-shaped around λ at higher λ values. Survival functions, both in PATHWAYS and NEMS, are a significant source of uncertainty. Given the long timeframe for this analysis, the choice of survival function distribution affects the timing of the results, but not the ability to meet a 2050 target.

At the beginning of the following year (y+1), PATHWAYS replaces retired stock and adds new stock to account for growth in the housing and equipment stock. The vintage of these new stock additions is then indexed to year y+1.

Equation 3

$$S.NEW_{y+1} = S.RET_y + S.GRW_y$$

We use this stock-rollover process to determine the composition of both the existing (pre-2010) and future (2011-2050) stock of residential buildings and equipment. For buildings, changes in stock composition include both housing type (single family, multi-family, mobile-home) and vintage. Different housing types have different energy service demands and average floor areas. Across housing types, building shell efficiency improves over time with increasing vintage, while increases in floor area increase energy service demand for some energy end uses. End use equipment efficiency generally improves with

[2] For more on the approach used in NEMS, see U.S. Energy Information Administration, "Residential Demand Module of the National Energy Modeling System: Model Documentation 2013," November 2013, http://www.eia.gov/forecasts/aeo/nems/documentation/residential/pdf/m067(2013).pdf.

vintage. The specifics of how new housing and end use equipment types are selected in the model are discussed in Section 2.2.2.1, below.

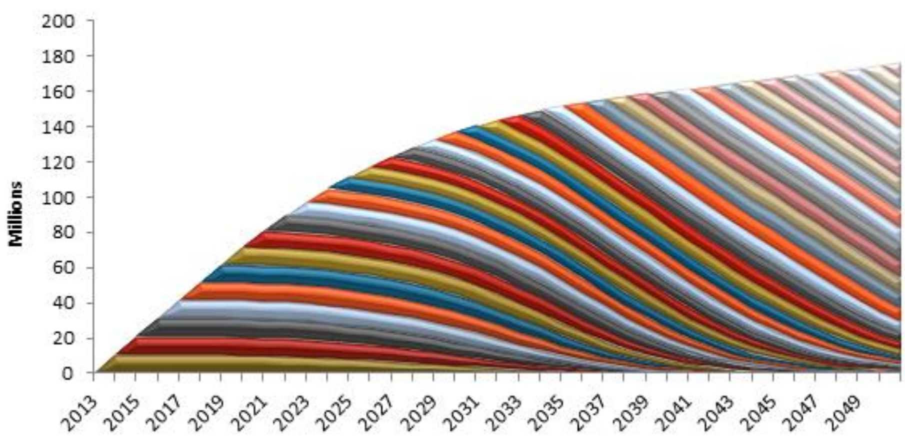
A simple example facilitates understanding of how the stock-rollover process drives changes in stock composition and vintage. Consider a region that has 200 homes in 1999, half of which (100) are single family and half of which are multi-family. All homes have an expected 50-year lifetime. Assume all of the single family homes were built in 1950, and all multi-family homes were built in 1960. At the end of 1999, the replacement coefficients for the single and multi-family homes will be 0.056 and 0.021, respectively,[3] indicating that 6 single family homes (=100 * 0.056) and 2 multi-family homes (=100 * 0.021) will be retiring at year's end. Assume, for illustration, that all 8 of these homes will be replaced with single family homes and that there is no growth in the housing stock. This means that, in year 2000, there will be 102 single family homes (= 100 – 6 + 8) and 98 multi-family homes (= 100 – 2 + 0). In 2000, single family homes account for 51% of the housing stock, an increase from 50% in 1999. All 8 homes that are replaced in 2000 will have a 2000 vintage, and will have higher building shell efficiency than previous vintages.

We use the same stock-rollover process for end use equipment, illustrated in Figure 2 for a specific residential water heater technology that has a 15-year expected useful lifetime. Each wedge in the figure represents an equipment vintage, and each wedge narrows and eventually declines to zero as the entire vintage is retired. For instance, the 2013 vintage has completely turned over by

[3] With an expected useful life of 50 years, the replacement coefficients for 50-year (i.e., built in 1950) and 40-year (built in 1960) homes are $e^{-50}\frac{50^{50}}{50!} = 0.056$ and $e^{-50}\frac{50^{40}}{40!} = 0.021$, respectively.

the early 2030s. The shape of the stock of this particular water heater technology (i.e., the aggregate curve) is governed by adoption saturation, described in greater detail in Section 2.2.2.3.

Figure 2. Illustration of stock-rollover process for residential water heaters (different colors represent different vintages)



2.2.2 FINAL ENERGY CONSUMPTION

PATHWAYS calculates residential final energy consumption (R.FEC) of different final energy types in each year as the product of two terms: (1) housing type-specific unit energy service demand (e.g., dishwasher cycles per year per single-family home in 2025) scaled by an activity driver (e.g., number of single-family homes in 2025); and (2) end use equipment efficiency that is weighted by the market share for a given vintage of a given type of equipment (e.g., the share of 2020 vintage LED lights in total residential light bulbs in 2025).

Equation 4

$$R.FEC_{ey} = \sum_{j}\sum_{k}\sum_{m}\sum_{v} ACT_{jy} \times ESD_{jky} \times \frac{MKS_{kmvey}}{EFF_{kmvey}}$$

New Subscripts

e	final energy type	electricity, pipeline gas, liquefied petroleum gas (LPG), fuel oil
y	year	model year (2010 to 2050)
j	home type	single family home, multi-family home, mobile home
k	end use	12 end uses in Table 3
m	equipment type	based on equipment types specific to the end uses in Table 3
v	vintage	equipment vintage (1950 to year y)

New Variables

$R.FEC_{ey}$	is residential final energy consumption of final energy type e in year y
ACT_{jy}	is an activity driver for home type j in year y
ESD_{jky}	is adjusted unit energy service demand per unit of activity for home type j for end use k in year y
MKS_{kmvey}	is the market share for vintage v of equipment type m consuming final energy type e for end use k in year y
EFF_{kmvey}	is the energy efficiency of vintage v of equipment type m consuming final energy type e for end use k in year y

Table 4 shows the equipment units, efficiency units, and final energy types associated with 11 of the 12 residential end uses (excluding "other").

Table 4. Residential Subsector Inputs

End use	Equipment units	Efficiency units	Final Energy Types
Water Heating	Water heater	BTU_{-out}/BTU_{-in}	Pipeline gas, electricity, fuel oil, LPG
Space Heating	Furnace, radiator, heat pump	BTU_{-out}/BTU_{-in}	Pipeline gas, electricity, fuel oil, LPG
Central Air Conditioning	Central air conditioner, heat pump	BTU_{-out}/BTU_{-in}	Electricity
Room Air Conditioning	Room air conditioner	BTU_{-out}/BTU_{-in}	Electricity
Lighting	Lamp or Bulb	Kilolumens/kilowatt	Electricity
Clothes Washing	Clothes Washer	BTU_{-out}/BTU_{-in}, normalized water use factor	Electricity
Clothes Drying	Clothes Dryer	BTU_{-out}/BTU_{-in}	Pipeline gas, electricity
Dishwashing	Dishwasher	$BTU_{-out}/BTU_{-in;}$ Normalized Water Use Factor	Electricity
Cooking	Range (oven and stovetop)	BTU_{-out}/BTU_{-in}	Pipeline gas, electricity, fuel oil, LPG
Refrigeration	Refrigerator	BTU_{-out}/BTU_{-in}	Electricity
Freezer	Freezer	BTU_{-out}/BTU_{-in}	Electricity

2.2.2.1 Activity Drivers

The Residential Sector Module's two activity drivers are households and floor area, segmented by housing unit type, and housing unit vintage. Projections of households are based on population projections out to 2050 from the California

Department of Finance estimates[4] and a linear regression that projects persons per household using data and estimates from 1990 to 2022, also from the California Department of Finance.

Equation 5

$$HPP_y = 0.3558 - 0.000475p$$

New Variables

HPP_y	is the number households per person in year y
P	p is year number, measured in annual increments from a base year (1990 = 1)

PATHWAYS uses total population and households per person to estimate the total number of households (THH) by census region and year.

Equation 6

$$THH_y = POP_y \times HPP_y$$

New Variables

THH_y	is the total number of households in year y
POP_y	is the projected population in year y

PATHWAYS projects future housing units by type and year using the stock-rollover approach described in Section 2.1, which allows for changes in housing

[4] http://www.dof.ca.gov/research/demographic/reports/projections/P-3/P-3_CAProj_database.zip

type, floor area, and vintage over time. Housing units that are being renovated or retired are then replaced with a new vintage and type of home. New vintage housing units of different types are also added as the number of households in each region grows.

Equation 7

$$THH_{jy+1} = \sum_{v}^{y} THH_{vjy} \times (1 - \beta_{vy}) + (THH_{vjy} \times \beta_{vy} + NHH_{y+1}) \times \theta_{jy}$$

New Variables

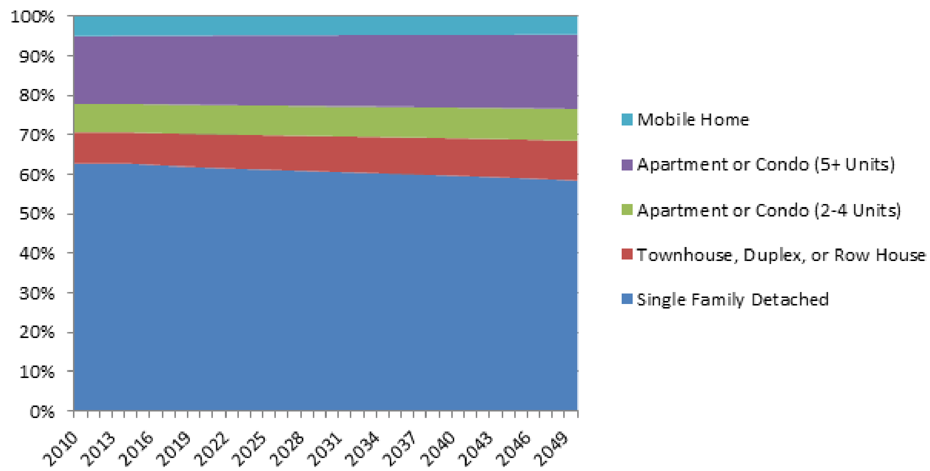
$\mathbf{THH_{jy+1}}$	is the number of housing units of type j in year y+1
$\mathbf{THH_{vjy}}$	is the number of housing units of vintage v and type j in year y
$\mathbf{NHH_{y}}$	is the number of new households in year y+1
$\boldsymbol{\theta_{jy}}$	is the share of housing unit type j in total housing units in year y

The replacement coefficients (β) are based on an expected 50-year lifetime for homes, where "lifetime" is more precisely defined as the time before retirement or renovation. To overcome the lack of data on housing vintages by type, we generate distributions of historical vintages of the existing (2010) housing stock by applying the stock-rollover retrospectively. The share coefficients (θ) are based on those found in California's 2009 Residential Appliance Saturation Survey (RASS 2009)[5]. This stock-rollover process leads to relatively small

[5] Documentation from http://www.energy.ca.gov/appliances/rass/; data from https://websafe.kemainc.com/RASS2009/Default.aspx

changes in the structure of the national housing stock over time, as shown in Figure 3.

Figure 3. Baseline housing stock by type and vintage over time



PATHWAYS projects total residential floor area by housing type using housing type-, and vintage-specific average floor areas (square feet per home) from RASS 2009.

Equation 8

$$RFA_{jy+1} = ARF_{jy+1} \times THH_{jy+1}$$

New Variables

$\mathbf{RFA_{jy+1}}$	is the total residential floor area for housing type j in year y
$\mathbf{ARF_{jy+1}}$	is the average residential floor area per housing type j in year y

2.2.2.2 Unit Energy Service Demand

In the residential sector, unit energy service demand is the demand for energy services (e.g., lumens, wash cycles, space heating) for each of the 12 end uses in Table 3 normalized by either household or floor area. Service demands vary across census regions (e.g., warmer regions need less heating) and housing unit types (e.g., multi-family units need less heat per square foot than single family homes).

2.2.2.2.1 Unit Energy Service Demand Adjustments

To arrive at a final unit energy service demand term, we account for end-use specific special cases. Space heating and cooling demand are dependent on changing climate conditions. Using RASS 2009, cooling demand in kWh/household is input separately for each housing type for each California climate zone. Similarly, annual heating in therms/household is input for each housing type for each utility service territory. Heating and cooling service demand are then moderated by the thermal performance of building shells. Shell performance multipliers (ratios to reference performance) for various potential shell improvements are based on those used in the AEO's NEMS model, where they are calculated using thermal simulation models. Building shells are tracked as stock technologies and can be influenced through building shell stock measures.

2.2.2.3 Equipment Measures, Adoption, and Market Shares

PATHWAYS reduces residential CO_2 emissions relative to a reference case through measures that change the composition of new building and equipment. Users implement residential measures in PATHWAYS by calibrating equipment-specific adoption curves. Adoption of new equipment leads to changes in market share for a given vintage and type of equipment over time.

In PATHWAYS, turnover of existing stock and new stock growth drive sales of new residential end use equipment. In the reference case, sales penetration for a given type of equipment — its share of new sales — is based on RASS 2009. Users change reference case sales penetrations by choosing the level and approximate timing of saturation for a given type of equipment (e.g., new sales of high efficiency heat pump water heaters saturate at 30% of total new water heater sales in 2030). PATHWAYS allows the user to choose between linear and S-shaped adoption curves. In the main report, sales penetrations (SPN) for most end uses are based on aggregated S-shaped curves

Equation 9

$$SPN_{kmvey} = \frac{SAT_{kme}}{1 + \propto^{x}}$$

where x is a scaling coefficient that shifts the curve over time based on a user defined measure start year and time-to-rapid-growth (TRG) period (in years)

Equation 10

$$x = \frac{MSY_{kme} + TRG_{kme} - y}{TRG_{kme}}$$

and TRG is calculated as

Equation 11

$$TRG_{kme} = \frac{ASY_{kme} - MSY_{kme}}{2}$$

New Variables

SPN_{kmvey}	is the sales penetration of vintage v of equipment type m for end use k using final energy type e in year y
SAT_{kme}	is the saturation level of equipment type m for end use k using final energy type e in a specified year
α	is a generic shape coefficient, which changes the shape of the S-curve
MSY_{kme}	is measure start year for equipment type m for end use k using final energy type e in a specified year
TRG_{kme}	is the time-to-rapid-growth for adoption of equipment type m for end use k using final energy type e in a specified year
ASY_{kme}	is the approximate saturation year for adoption of equipment type m for end use k using final energy type e

Market shares for an equipment vintage in a given year are the initial stock of that vintage, determined by the adoption curve, minus the stock that has turned over and been replaced, divided by the total stock of equipment in that year (e.g., the share of 2020 vintage LEDs in the total stock of lighting equipment in 2025).

Equation 12

$$MKS_{kmvey+1} = \frac{EQP_{vkme} - \sum_{v}^{y} EQP_{vkme} \times \left(1 - \beta_{vy}\right)}{EQP_{ky+1}}$$

New Variables

$MKS_{kmvey+1}$	is the market share of vintage v of equipment type m for end use k using final energy type e in year y+1
EQP_{vkme}	is the stock of equipment adopted of equipment type m for end use k using final energy type e that has vintage v
EQP_{ky}	is the total stock of equipment for end use k in year y+1

If total sales of new equipment exceed sales of user-determined measures (i.e., if the share of measures in new sales is less than 100% in any year), adoption of residual equipment is assumed to match that in the reference case. In cases where adoption may be over-constrained, PATHWAYS normalizes adoption saturation so that the total share of user-determined measures in new sales never exceeds 100% in any year.

2.2.3 CO_2 EMISSIONS

We calculate total CO_2 emissions from the residential sector in each year as the sum product of final energy consumption and a CO_2 emission factor by fuel type.

Equation 13

$$R.CO2_y = \sum_e R.FEC_{ey} \times CEF_e$$

Variables

$R.CO2_y$	is residential CO_2 emissions in year y
CEF_e	CEF_e is a CO_2 emission factor for energy type e, which is time invariant

All CO_2 emission factors for primary energy are based on higher heating value (HHV)-based emission factors used in AEO 2013. CO_2 emission factors for energy carriers are described in the Energy Supply section. In cases where electricity sector CO_2 emissions are reported separately from residential sector emissions, the R.FEC term in the above equation is zeroed out.

2.2.4 ENERGY SYSTEM COSTS

Energy system costs are defined in PATHWAYS as the incremental capital and energy cost of measures. The incremental cost of measures is measured relative to a reference technology, which is based on the equipment that was adopted in the Reference Case.

2.2.4.1 Capital Costs

PATHWAYS calculates end use capital (equipment and building efficiency) costs by vintage on an annualized ($/yr) basis, where annual residential equipment costs (R.AQC) are the total residential equipment cost (R.TQC) multiplied by a capital recovery factor (CRF).

Equation 14

$$R.AQC_{kmv} = R.TQC_{kmv} \times CRF$$

Equation 15

$$CRF = \frac{r}{[1-(1+r)^{-EUL_m}]}$$

Variables

$R.AQC_{kmv}$	is the annual residential equipment cost for vintage v of equipment type m in end use k
$R.TQC_{kmv}$	is the total residential equipment cost for vintage v of equipment type m in end use k
r	is a time, housing type, region, and equipment invariant discount rate
EUL_m	is the expected useful life of equipment type m

PATHWAYS uses a discount rate of 10%, reflecting the historical average of real credit card interest rates.[6] This discount rate is not intended to be a hurdle rate, and is not used to forecast technology adoption. Rather, it is meant to be a broad reflection of the opportunity cost of capital to households.

Consistent with our stock-rollover approach to adoption and changes in the equipment stock, we differentiate between the cost of equipment that is replaced at the end of its expected useful life ("natural replacement"), and equipment that is replaced before the end of its useful life ("early replacement"). The incremental cost of equipment that is naturally replaced is

[6] This roughly reflects the historical average of real credit card interest rates. From, 1974 to 2011, the CPI-adjusted annual average rate was 11.4%. Real rates are calculated as $r^R = \frac{(1+r^N)}{(1+i)} - 1$, where i is a rate of consumer inflation based on the CPI.

the annual cost of that equipment minus the annual cost of equipment used in the reference case.

Equation 16

$$R.IQC_{kmv} = R.AQC_{kmv} - R.AQC'_{kmv}$$

New Variables

R.IQC$_{kmv}$	is the incremental annual residential equipment cost in end use k
R.AQC$_{kmv}$	is the annual residential equipment cost for equipment type m that consumes final energy type e in end use k for a given scenario examined in this report
R.AQC'$_{kmv}$	is the annual residential equipment cost for equipment type m that consumes final energy type e in end use k for the reference case

For equipment, early replacement measures are assessed the full technology cost and do not include any salvage value.

PATHWAYS calculates total incremental residential end use equipment costs in year y as the sum of annual incremental costs across vintages, equipment types, and end uses.

Equation 17

$$R.IQC_y = \sum_k \sum_m \sum_v^y R.IQC_{kmv}$$

New Variables

R.IQC$_y$	is the total incremental cost of residential end use equipment in year y

2.2.4.2 Energy Costs

Annual residential energy costs (R.AEC) in PATHWAYS are calculated by multiplying final energy consumption (R.FEC) by final energy type in each year by a unit energy price (P) in that year.

Equation 18

$$R.AEC_{ey} = R.FEC_{ey} \times P_{ey}$$

New Variables

R.AEC$_{ey}$	is the total annual residential energy cost for final energy type e in year y
P$_{ey}$	Is the unit price of final energy type e in year y

Electricity and fuel prices are calculated in the supply side modules, described in the Energy Supply section. Incremental annual residential energy costs are calculated relative to the reference case.

Equation 19

$$R.IEC_{ey} = R.AEC_{ey} - R.AEC'_{ey}$$

New Variables

R.IEC$_{ey}$	is the total incremental annual residential energy cost for final energy type e in year y
R.AEC'$_{ey}$	is the total annual residential energy cost for final energy type e in year y in the reference case

2.2.5 MODEL DATA INPUTS AND REFERENCES

Table 5: Model Data Inputs

Title	Units	Description	Reference
Capacity:RES LT	Lamps or Bulbs/Sq. Ft.	Lamps or bulbs per square foot	Data used in support of AEO 2013 from the National Energy Modeling System: Input filenames "rmslgt.txt".
Data:RES OT Ele	GWh	Sectoral electricity demand input data	Energy Demand 2010-2020, Adopted Forecast, California Energy Commission, December 2009, CEC-200-2009-012-CMF
Data:RES OT Gas	Mtherms	Sectoral pipeline gas demand input data	KEMA, 2009. California RASS.
Data:RES OT Oth	GDE	Sectoral "other" energy input data. Input	«null»
Ene Usage Tar:RES CA	GWh	Calibration energy usage target	Energy Demand 2010-2020, Adopted Firecast, California Energy Commission, December 2009, CEC-200-2009-012-CMF

Title	Units	Description	Reference
Ene Usage Tar:RES CD	GWh	Calibration energy usage target	Energy Demand 2010-2020, Adopted Forecast, California Energy Commission, December 2009, CEC-200-2009-012-CMF
Ene Usage Tar:RES CK	GWh	Calibration energy usage target	2009 residential gas usage demand from CEC Energy Consumption database Water heating share of residential natural gas usage from: KEMA, 2009. California RASS
Ene Usage Tar:RES CW	GWh	Calibration energy usage target	Energy Demand 2010-2020, Adopted Forecast, California Energy Commission, December 2009, CEC-200-2009-012-CMF
Ene Usage Tar:RES DW	GWh	Calibration energy usage target	Energy Demand 2010-2020, Adopted Forecast, California Energy Commission, December 2009, CEC-200-2009-012-CMF
Ene Usage Tar:RES FR	GWh	Calibration energy usage target	Energy Demand 2010-2020, Adopted Forecast, California Energy Commission, December 2009, CEC-200-2009-012-CMF
Ene Usage Tar:RES LT	GWh	Calibration energy usage target	Energy Demand 2010-2020, Adopted Firecast, California Energy Commission, December 2009, CEC-200-2009-012-CMF
Ene Usage Tar:RES RA	GWh	Calibration energy usage target	Energy Demand 2010-2020, Adopted Firecast, California Energy Commission, December 2009, CEC-200-2009-012-CMF

Title	Units	Description	Reference
Ene Usage Tar:RES RF	GWh	Calibration energy usage target	Energy Demand 2010-2020, Adopted Firecast, California Energy Commission, December 2009, CEC-200-2009-012-CMF
Ene Usage Tar:RES SH	Therms	Calibration energy usage target	2009 residential gas usage demand from CEC Energy Consumption database Water heating share of residential natural gas usage from: KEMA, 2009. California RASS
Ene Usage Tar:RES WH	Therms	Calibration energy usage target	2009 residential gas usage demand from CEC Energy Consumption database Water heating share of residential natural gas usage from: KEMA, 2009. California RASS
Inter Share:RES WH	Normalized	% of residential water heating associated with other demand subsectors (i.e. clothes washing and clothes drying)	Energy Demand 2010-2020, Adopted Forecast, California Energy Commission, December 2009, CEC-200-2009-012-CMF
Stock Share:RES BS	% of Stock	Reference technology shares	Kema, 2009. California RASS.
Stock Share:RES CA	% of Stock	Reference technology shares	KEMA, 2009. California RASS.
Stock Share:RES CD	% of Stock	Reference technology shares	KEMA, 2009. California RASS. % of high efficiency clothes washers based on 2013 Navigant Potential Study

Title	Units	Description	Reference
Stock Share:RES CK	% of Stock	Reference technology shares	KEMA 2009, California RASS.
Stock Share:RES CW	% of Stock	Reference technology shares	KEMA, 2009. California RASS. % of high efficiency clothes washers based on 2013 Navigant Potential Study
Stock Share:RES DW	% of Stock	Reference technology shares	KEMA, 2009. California RASS. % of high efficiency dishwashers based on 2013 Navigant Potential Study
Stock Share:RES FR	% of Stock	Reference technology shares	KEMA, 2009. California RASS.
Stock Share:RES HS	% of Stock	Reference technology shares	Kema, 2009. California RASS.
Stock Share:RES LT	% of Stock	Reference technology shares	2010 DOE Lighting Market Characterization Report Tables
Stock Share:RES RA	% of Stock	Reference technology shares	Kema, 2009. California RASS.
Stock Share:RES RF	% of Stock	Reference technology shares	KEMA, 2009. California RASS.
Stock Share:RES SH	% of Stock	Reference technology shares	Kema, 2009. California RASS.
Stock Share:RES WH	% of Stock	Reference technology shares	Kema, 2009. California RASS for LPG. Share of electric/gas adjusted for top-down demand forecasts.

Title	Units	Description	Reference
Supply Adj:RES CD	«null»	Stock saturation used to compute energy is not equal to total equipment stocks because common area units are included in stock saturation. Assumption is 4 households per stock unit.	KEMA, 2009. California RASS.
Supply Adj:RES CD	«null»	Same as above.	KEMA, 2009. California RASS.
Supply Adj:RES CW	«null»	Same as above.	KEMA, 2009. California RASS.
Supply Adj:RES CW	«null»	Same as above.	KEMA, 2009. California RASS.
Tech Input:RES BS	«null»	Technology inputs including useful life, energy type, and cost assumptions	Data used in support of AEO 2013 from the National Energy Modeling System: Input filenames "rsclass.txt".
Tech Input:RES CA	«null»	Same as above.	Same as above.
Tech Input:RES CD	«null»	Same as above.	Same as above.
Tech Input:RES CK	«null»	Same as above.	Same as above.
Tech Input:RES CW	«null»	Same as above.	Same as above.
Tech Input:RES DW	«null»	Same as above.	Same as above.

Title	Units	Description	Reference
Tech Input:RES FR	«null»	Same as above.	Same as above.
Tech Input:RES LT	«null»	Same as above.	Data used in support of AEO 2013 from the National Energy Modeling System: Input filenames "rsmlgt.txt" DOE, 2012: Energy Savings Potential of Solid-State Lighting in General Illumination Applications
Tech Input:RES RA	«null»	Same as above.	Data used in support of AEO 2013 from the National Energy Modeling System: Input filenames "rsclass.txt".
Tech Input:RES RF	«null»	Same as above.	Same as above..
Tech Input:RES SH	«null»	Same as above.	Data used in support of AEO 2013 from the National Energy Modeling System: Input filenames "rsclass.txt".
Tech Input:RES WH	«null»	Same as above.	Same as above.
UEC or DEM:RES CA	kWh/house hold	Subsector energy or service demand consumption estimate used to calibrate total service demand	KEMA, 2009. California RASS
UEC or DEM:RES CD	kWh/house hold	Same as above.	KEMA, 2009. California RASS.
UEC or DEM:RES CK	MMBTU/ho usehold	Same as above.	KEMA, 2009. California RASS.
UEC or DEM:RES CW	kWh/house hold	Same as above.	KEMA, 2009. California RASS.

Title	Units	Description	Reference
UEC or DEM:RES DW	Cycles/household	Same as above.	Energy Star Program Requirements and Criteria for Dishwashers
UEC or DEM:RES FR	kWh	Same as above.	KEMA, 2009. California RASS.
UEC or DEM:RES LT	klumen-hrs/sq ft	Same as above.	Data used in support of AEO 2013 from the National Energy Modeling System: Input filenames "rmslgt.txt".
UEC or DEM:RES RA	kWh/household	Same as above.	KEMA, 2009. California RASS
UEC or DEM:RES RF	kWh	Same as above.	KEMA, 2009. California RASS
UEC or DEM:RES SH	Therms/household	Same as above.	KEMA, 2009. California RASS
UEC or DEM:RES WH	Therms/household	Same as above.	KEMA, 2009. California RASS.
Vin Sq Ft:RES HS	Sq. Ft	«null»	KEMA, 2009. California RASS.
Vintage Cost:RES BS	$/Sq Ft	Per-unit technology costs	Data used in support of AEO 2013 from the National Energy Modeling System: Input filenames "rsmeqp.txt".
Vintage Cost:RES CA	$/Unit	Per-unit technology costs	Same as above.
Vintage Cost:RES CD	$/Clothes Dryer	Per-unit technology costs	Same as above.

Title	Units	Description	Reference
Vintage Cost:RES CK	$/Range	Per-unit technology costs	Same as above.
Vintage Cost:RES CW	$/Clothes Washer	Per-unit technology costs	Same as above.
Vintage Cost:RES DW	$/Dishwash er	Per-unit technology costs	Same as above.
Vintage Cost:RES FR	$/Refrigerat or	Per-unit technology costs	Same as above.
Vintage Cost:RES LT	$/Lamp or Bulb	Per-unit technology costs, from US Model	Cost projections are taken from data used in support of AEO 2013 from the National Energy Modeling System: Input filenames “rsmlgt.txt” or from the report Energy Savings Potential of Solid-State Lighting in General Illumination Applications for technologies not sufficiently characterized by NEMS (specifically LED lamps and luminaires).
Vintage Cost:RES RA	$/Unit	Per-unit technology costs	Data used in support of AEO 2013 from the National Energy Modeling System: Input filenames “rsmeqp.txt”.
Vintage Cost:RES RF	$/Refrigerat or	Per-unit technology costs	Same as above.
Vintage Cost:RES SH	$/Furnace	Per-unit technology costs	Same as above.

Title	Units	Description	Reference
Vintage Cost:RES WH	$/Water Heater	Per-unit technology costs	Same as above.
Vintage Eff:RES BS	Shell Index	Technology efficiencies	Data used in support of AEO 2013 from the National Energy Modeling System: Input filename “rsmshl.txt”
Vintage Eff:RES CA	HSPF	Technology efficiencies	Data used in support of AEO 2013 from the National Energy Modeling System: Input filename “rsmeqp.txt”
Vintage Eff:RES CD	Energy Factor (lb/kWh)	Technology efficiencies	Same as above.
Vintage Eff:RES CK	Normalized	Technology efficiencies	Data used in support of AEO 2013 from the National Energy Modeling System: Input filename “rsmeqp.txt”. Adjusted from UEC values taken from "rsuec.txt"and stock efficiencies from "rsstkeff.txt".
Vintage Eff:RES CW	Cycles/kWh-Water Factor	Technology efficiencies	Data used in support of AEO 2013 from the National Energy Modeling System: Input filename “rsmeqp.txt”
Vintage Eff:RES DW	Cycles/kWh-Water Factor	Technology efficiencies	Data used in support of AEO 2013 from the National Energy Modeling System: Input filename “rsmeqp.txt" and "rsstkeff.txt"
Vintage Eff:RES FR	Normalized	Technology efficiencies	Same as above.
Vintage Eff:RES LT	klumens/kW	Technology efficiencies	DOE, 2012. Energy Savings Potential of Solid-State Lighting in General Illumination Applications.

Title	Units	Description	Reference
Vintage Eff:RES RA	HSPF	Technology efficiencies	Data used in support of AEO 2013 from the National Energy Modeling System: Input filename "rsmeqp.txt"
Vintage Eff:RES RF	Normalized	Technology efficiencies	Same as above.
Vintage Eff:RES SH	AFUE	Technology efficiencies	Same as above.
Vintage Eff:RES WH	Energy Factor	Technology efficiencies	Same as above.

2.3 Commercial

PATHWAYS' Commercial Module is used to project commercial sector final energy consumption, CO_2 emissions, and end-use equipment costs by the eight end uses shown in Table 6 and the seven fuels shown in

Table 7. The first seven end uses are represented at a technology level, while the "Other" subsector is represented on an aggregate basis.[7]

[7] Electricity Data from Energy Demand 2010-2020, Adopted Forecast, California Energy Commission, December 2009, CEC-200-2009-012-CMF (http://www.energy.ca.gov/2009publications/CEC-200-2009-012/). Gas data from Integrated Energy Policy Report (IEPR) 2014 - Mid Demand Case (http://www.energy.ca.gov/2014_energypolicy/). In general, we make few adjustments to this end use because of the lack of visibility into what it actually contains.

Table 6. Commercial end uses and model identifiers

Subsector	Model Identifier
Air Conditioning	AC
Cooking	CK
Lighting	LT
Refrigeration	RF
Space Heating	SH
Ventilation	VT
Water Heating	WH
Other	OT

Table 7. Fuels used in the commercial sector

Fuel
Electricity
Pipeline Gas
Fuel Oil
Liquefied Petroleum Gas (LPG)
Kerosene
Wood
Waste Heat

Changes in final energy consumption, CO_2 emissions, and end use equipment costs in the Commercial Module are driven by changes to the stock of buildings and energy end use equipment, which grow, rollover (retire), and are replaced over time. Stock growth and replacement — new stock — provides an opportunity for efficiency improvements in buildings and equipment, and for fuel switching through changes in equipment. Users reduce commercial CO_2 emissions in PATHWAYS by implementing measures that change the equipment stock over time. Users can also implement Demand Change Measures that directly alter the demand for services met by equipment. For example, water efficiency efforts translate into reduced water heating loads and office illumination levels are trending downwards due to increasing use of computer monitors rather than paper for work tasks.

This section provides an overview of the mechanics of the stock-rollover process at the heart of the Commercial Module (Section 2.3.1), and describes methods for calculating final energy consumption (Section 2.3.2), CO_2 emissions (Section 2.3.3), and energy system costs (Section 2.3.4). The section closes with a list of data inputs and sources (Section 2.3.5).

2.3.1 COMMERCIAL STOCK-ROLLOVER MECHANICS

The Commercial Module includes a stock-rollover mechanism that governs changes in commercial building stock composition, floor area, end use equipment efficiency, fuel switching opportunities, and equipment cost over time. The mechanism tracks building and equipment vintage — the year in which a building was constructed or a piece of equipment purchased — by utility service territory (LADWP, PG&E, SDG&E, SCE, SMUD, or Other).

At the end of each year, PATHWAYS retires or renovates some amount of a given equipment type in a given region ($S.RET_y$), by multiplying the existing stock of each vintage ($S.EXT_{vy}$) by a replacement coefficient (β_{vy}).

Equation 20

$$S.RET_y = \sum_{v}^{y} S.EXT_{vy} \times \beta_{vy}$$

New Subscripts

y	year	is the model year (2010 to 2050)
v	vintage	is the equipment vintage (1950 to year y)

New Variables

$S.RET_y$	is the amount of existing stock of equipment retired or renovated in year y
$S.EXT_{vy}$	is the existing stock of equipment with vintage v in year y
β_{vy}	is a replacement coefficient for vintage v in year y

The replacement coefficients are generated by a survival function that uses Poisson distribution, with a mean (λ) equal to the expected useful life of the building or equipment.

Equation 21

$$\beta_{vy} = e^{-\lambda} \frac{\lambda^{y-v+1}}{(y-v+1)!}$$

PATHWAYS uses the Poisson distribution as an approximation to the survival functions in the NEMS Commercial Demand Module, which are based on a combination of logistic and linear survival functions.[8] The Poisson distribution has a right-skewed density function, which becomes more bell-shaped around λ at higher λ values. Survival functions, both in PATHWAYS and NEMS, are a significant source of uncertainty. Given the long timeframe for this analysis, the choice of survival function distribution affects the timing of the results, but not the ability to meet a 2050 target.

At the beginning of the following year (y+1), PATHWAYS replaces retired stock and adds new stock to account for growth in the building and equipment stock. The vintage of these new stock additions is then indexed to year y+1.

Equation 22

$$S.NEW_{y+1} = S.RET_y + S.GRW_y$$

We use this stock-rollover process to determine the composition of both the existing (pre-2010) and future (2011-2050) stock of commercial buildings and equipment. Building floor areas are projected by vintage and utility service territory. Energy service demand for all end uses is proportional to floor area, with total demand calibrated to historical demand data. In line with NEMS technology characterizations, end use equipment efficiency for each equipment type incrementally improves with vintage. The specifics of how new end use equipment types are selected in the model are discussed in Section 2.3.2.1, below.

[8] For more on the approach used in NEMS, see U.S. Energy Information Administration, "Commercial Demand Module of the National Energy Modeling System: Model Documentation 2013," November 2013, http://www.eia.gov/forecasts/aeo/nems/documentation/commercial/pdf/m066(2013).pdf.

2.3.2 FINAL ENERGY CONSUMPTION

PATHWAYS calculates commercial final energy consumption (C.FEC) of different final energy types in each year as the product of two main terms: (1) service-territory-specific unit energy service demand (e.g., water heating demand in PG&E's territory in 2025) and (2) end use equipment efficiency that is weighted by the market share for a given vintage of a given type of equipment in a territory (e.g., the share of 2020 vintage high efficiency heat pump water heaters in total commercial water heating equipment in PG&E's territory in 2025).

Table 8 shows the equipment units, efficiency units, and final energy types associated with commercial end uses, excluding "other".

Table 8. Commercial Subsector Inputs

End use	Equipment units	Efficiency units	Final Energy Types
Air Conditioning	Air conditioner	BTU_{-Out}/BTU_{-in}	Electricity
Cooking	Range	BTU_{-Out}/BTU_{-in}	Pipeline gas, electricity
Lighting	Lamp or Bulb	Kilolumens/kilowatt	Electricity
Refrigeration	Refrigerator	BTU_{-Out}/BTU_{-in}	Electricity
Space Heating	Furnace, radiator, heat pump	BTU_{-Out}/BTU_{-in}	Pipeline gas, electricity, waste heat
Ventilation	Ventilation system	BTU_{-Out}/BTU_{-in}	Electricity
Water Heating	Water heater	BTU_{-Out}/BTU_{-in}	Pipeline gas, electricity

2.3.2.1 Activity Drivers

The Commercial Module's main activity driver is commercial floor area, segmented by utility service territory. Total commercial building floor area estimates per utility service territory from 1990 to 2024 are provided by the CEC's California Energy Demand 2014-2024 Final Forecast Mid-Case.[9] Floor areas for the remaining years up to 2050 are projected for each service territory using linear regression. Figure 4 provides a visualization of the resulting commercial floor space trends for each service territory from 2010 to 2050.

[9] http://www.energy.ca.gov/2013_energypolicy/documents/demand-forecast/mid_case/

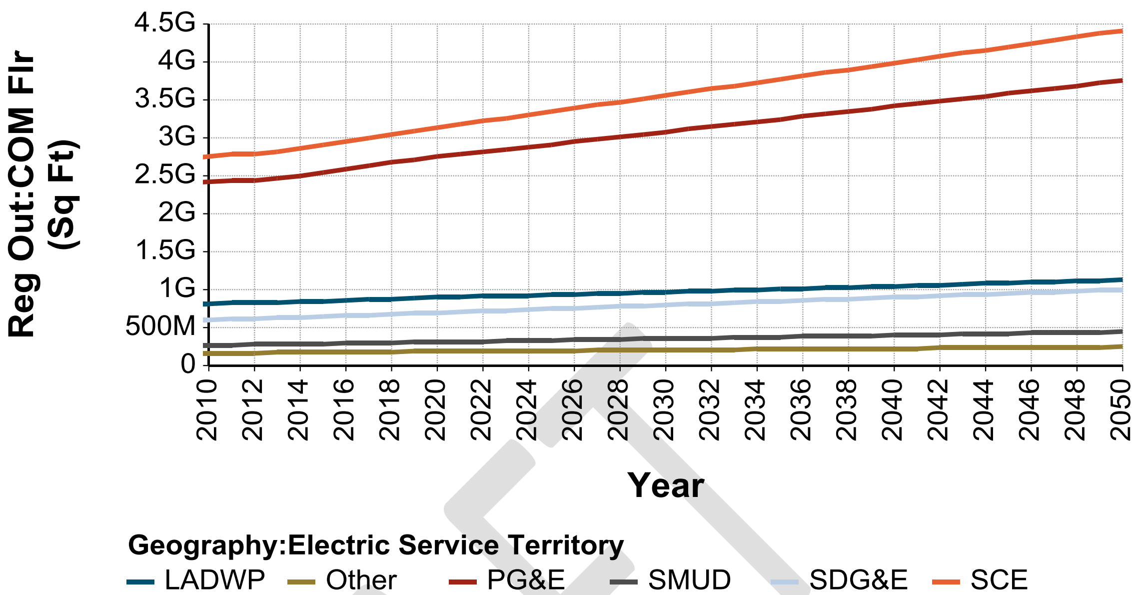


Figure 4: Total commercial floor space for each utility service territory, projected to 2050

2.3.2.2 Unit Energy Service Demand

In the commercial sector, unit energy service demand is the demand for energy services (e.g., lumens, space heating, space cooling) for each of the 8 end uses in Table 6 normalized by floor area. The service demand is derived from Unit Energy Consumption measured at the end use level for each service territory as reported in CEUS (2006). This source doesn't include numbers for all service territories, so SCE values are used for LADWP and Other, based on geographic proximity. To arrive at a unit energy service demand term, we multiply the unit energy demand (i.e. the measured energy consumption) by the aggregate efficiency of the stock (i.e. the fraction of energy that delivers the service) for a given calibration year, typically 2009.

Equation 23: Unit Energy Service calculation

$$UES_{eik} = \left(UED_{eiky} \times \sum_{m} \sum_{v} \frac{MKS_{ikmvey}}{EFF_{kmvey}} \right)_{y=2009}$$

New Subscripts

e	final energy type	electricity, pipeline gas, liquefied petroleum gas (LPG), fuel oil
y	year	in the model year (2010 to 2050)
i	utility territory	Geographic territory for LADWP, PG&E, SDG&E, SCE, SMUD, and Other
k	end use	8 end uses in Table 6
m	equipment type	based on equipment types specific to the end uses in Table 6
v	vintage	equipment vintage (1950 to year y)

New Variables

UES_{eik}	is the unit energy service requirement (service demand per square foot) for energy type e in territory i for end use k (evaluated in the year 2009)
UED_{ieky}	is the measured energy demand per square foot for energy type e in territory i for end use k in year y
MKS_{ikmvey}	is the market share for vintage v of equipment type m consuming final energy type e for end use k in territory i in year y
EFF_{kmvey}	is the energy efficiency of vintage v of equipment type m consuming final energy type e for end use k in year y

Note that this unit energy service demand is calculated using a bottom-up end use intensity metric. To ensure that the bottom-up calculations match the top down measured commercial energy consumption, the UES is calibrated against top down commercial measured energy consumption data, C.MEC[10].

Equation 24: Adjusted service demand

$$ESD_{eik} = UES_{eik} \times \left(\frac{\sum_k \sum_i UES_{eik} \times ACT_{iy}}{C.MEC_{ey}} \right)_{y=2009}$$

New Variables

ESD_{eik}	is the adjusted energy service demand per sqft for energy type e in territory i for end use k
$C.MEC_{ey}$	is the measured total commercial energy demand for energy type e in year y
ACT_{iy}	is an activity driver, i.e. floor space, for service territory i in year y

[10] In this case we use the total commercial gas usage from the 2014 IEPR, split by end use shares of usage according to CEUS, 2006.

Equation 25: Commercial final energy

$$C.FEC_{ey} = \sum_{i}\sum_{k}\sum_{m}\sum_{v} ACT_{iy} \times ESD_{iek} \times DCF_{key} \times \frac{MKS_{ikmvey}}{EFF_{kmvey}}$$

New Variables

$C.FEC_{ey}$	is commercial final energy consumption of final energy type e in year y
DCF_{key}	Is the demand change factor (default is 1, or no change) introduced by demand change measures for energy type e within end use k in year y

2.3.2.3 Equipment Measures, Adoption, and market Shares

PATHWAYS reduces commercial CO_2 emissions relative to a reference case through measures that change the composition of equipment in the stock. Users implement commercial measures in PATHWAYS by calibrating equipment-specific adoption curves. Adoption of new equipment leads to changes in market share for a given vintage and type of equipment over time.

In PATHWAYS, turnover of existing stock and new stock growth drive sales of new commercial end use equipment. In the Reference scenario, retiring stock of a given type of equipment is replaced by the same type. In other words, its share of new sales maintains its historical penetration. Users change reference case sales penetrations by choosing the level and approximate timing of saturation for a given type of equipment (e.g., new sales of high efficiency heat pump water heaters saturate at 30% of total new water heater sales in 2030). PATHWAYS allows the user to choose between linear and S-shaped adoption curves. In general, sales penetrations (SPN) for most end uses are based on aggregated S-shaped curves.

Equation 26

$$SPN_{kmvey} = \frac{SAT_{kme}}{1 + \propto^{x}}$$

Equation 26 defines the SPN, where x is a scaling coefficient that shifts the curve over time based on a user defined measure start year and time-to-rapid-growth period (in years). Equation 27 defines the scaling coefficient x, where TRG is calculated in Equation 28.

Equation 27

$$x = \frac{MSY_{kme} + TRG_{kme} - y}{TRG_{kme}}$$

Equation 28

$$TRG_{kme} = \frac{ASY_{kme} - MSY_{kme}}{2}$$

New Variables

SPN_{kmvey}	is the sales penetration of vintage v of equipment type m for end use k using final energy type e in year y
SAT_{kme}	is the saturation level of equipment type m for end use k using final energy type e in a specified year
α	is a generic shape coefficient, which changes the shape of the S-curve
MSY_{kme}	is measure start year for equipment type m for end use k using final energy type e in a specified year
TRG_{kme}	is the time-to-rapid-growth for adoption of equipment type m for end use k using final energy type e in a specified year
ASY_{kme}	is the approximate saturation year for adoption of equipment type m for end use k using final energy type e

Market shares for an equipment vintage in a given year are the initial stock of that vintage, determined by the adoption curve, minus the stock that has turned over and been replaced, divided by the total stock of equipment in that year (e.g., the share of 2020 vintage LEDs in the total stock of lighting equipment in 2025).

Equation 29

$$MKS_{kmvey+1} = \frac{EQP_{vkme} - \sum_{v}^{y} EQP_{vkme} \times \left(1 - \beta_{vy}\right)}{EQP_{ky+1}}$$

New Variables

$MKS_{kmvey+1}$	is the market share of vintage v of equipment type m for end use k using final energy type e in year y+1
EQP_{vkme}	is the stock of equipment adopted of equipment type m for end use k using final energy type e that has vintage v
EQP_{ky}	is the total stock of equipment for end use k in year y+1

If total sales of new equipment exceed sales of user-determined measures (i.e., if the share of measures in new sales is less than 100% in any year), adoption of residual equipment is assumed to match that in the reference case. In cases where adoption may be over-constrained, PATHWAYS normalizes adoption saturation so that the total share of user-determined measures in new sales never exceeds 100% in any year.

Given the large number of potential measures, equipment adoption in PATHWAYS is generally not done by utility service territory. Instead, equipment is allocated through equipment ownership, which is determined by building stock in each service territory.

2.3.3 CO_2 EMISSIONS

PATHWAYS calculates total CO_2 emissions from the commercial sector in each year as the sum product of final energy consumption and a CO_2 emission factor by energy type.

Equation 30

$$C.CO2_y = \sum_e C.FEC_{ey} \times CEF_e$$

Variables

$C.CO2_y$	is commercial CO_2 emissions in year y
CEF_e	CEF_e is a CO_2 emission factor for energy type e, which is time invariant

All CO_2 emission factors for primary energy are based on higher heating value (HHV)-based emission factors used in AEO 2013. CO_2 emission factors for energy carriers are described in a separate section. In cases where electricity sector CO_2 emissions are reported separately from commercial sector emissions, the C.FEC term in the above equation is zeroed out.

2.3.4 ENERGY SYSTEM COSTS

Energy system costs are defined in PATHWAYS as the incremental capital and energy cost of measures. The incremental cost of equipment is measured relative to a reference technology, which is based on the equipment that was adopted in the Reference Case.

2.3.4.1 Capital Costs

PATHWAYS calculates end use capital (equipment and building efficiency) costs by vintage on an annualized ($/yr) basis, where annual commercial equipment costs (C.AQC) are the total commercial equipment cost (C.TQC) multiplied by a capital recovery factor (CRF).

Equation 31

$$C.AQC_{kmv} = C.TQC_{kmv} \times CRF$$

Equation 32

$$CRF = \frac{r}{[1 - (1 + r)^{-EUL_m}]}$$

Variables

$C.AQC_{kmv}$	is the annual commercial equipment cost for vintage v of equipment type m in end use k
$C.TQC_{kmv}$	is the total commercial equipment cost for vintage v of equipment type m in end use k
r	is a time, building type, region, and equipment invariant discount rate
EUL_m	is the expected useful life of equipment type m

PATHWAYS uses a discount rate of 10%, roughly approximating an average pretax return on investment. This discount rate is not intended to be a hurdle rate, and is not used to forecast technology adoption. Rather, it is meant to be a broad reflection of the opportunity cost of capital to firms.

Consistent with the stock-rollover approach to adoption and changes in the equipment stock, PATHWAYS differentiate between the cost of equipment that is replaced at the end of its expected useful life ("natural replacement"), and equipment that is replaced before the end of its useful life ("early replacement"). The incremental cost of equipment that is naturally replaced is the annual cost of that equipment minus the annual cost of equipment used in the Reference scenario.

Equation 33

$$C.IQC_{kmv} = C.AQC_{kmv} - C.AQC'_{kmv}$$

New Variables

$C.IQC_{kmv}$	is the incremental annual commercial equipment cost in end use k
$C.AQC_{kmv}$	is the annual commercial equipment cost for equipment type m that consumes final energy type e in end use k for a given scenario examined in this report
$C.AQC'_{kmv}$	is the annual commercial equipment cost for equipment type m that consumes final energy type e in end use k for the reference case

PATHWAYS calculates total incremental commercial end use equipment costs in year y as the sum of annual incremental costs across vintages, equipment types, and end uses.

Equation 34

$$C.IQC_y = \sum_k \sum_m \sum_v^y C.IQC_{kmv}$$

New Variables

$C.IQC_y$	is the total incremental cost of commercial end use equipment in year y

2.3.4.2 Demand Change Measure costs

For demand change measures, energy efficiency costs are the product of measure-specific reductions in energy service demand and the measure-specific levelized cost of implementation (LC).

Equation 35: Annualized demand change measure costs

$$C.FMC_y = \sum_e \sum_r \sum_k MEI_{krey} \times LC_r$$

New Variables

$C.FMC_y$	Demand change measure costs
MEI_{kmey}	Measure energy impact for measure r with final energy type e for end use k in year y
LC_r	Input levelized costs for measure r

2.3.4.3 Energy Costs

Annual commercial energy costs (C.AEC) in PATHWAYS are calculated by multiplying final energy consumption (C.FEC) by final energy type in each year by a unit energy price (P) in that year and adding the annual demand change measure costs.

Equation 36

$$C.AEC_{ey} = C.FEC_{ey} \times P_{ey} + C.FMC_y$$

New Variables

$C.AEC_{ey}$	is the total annual commercial energy cost for final energy type e in year y
P_{ey}	Is the unit price of final energy type e in year y

Electricity and fuel prices are calculated in the supply side modules, described elsewhere. Incremental annual commercial energy costs are calculated relative to the Reference scenario.

Equation 37

$$C.IEC_{ey} = C.AEC_{ey} - C.AEC'_{ey}$$

New Variables

$C.IEC_{ey}$	is the total incremental annual commercial energy cost for final energy type e in year y
$C.AEC'_{ey}$	is the total annual commercial energy cost for final energy type e in year y in the reference case

2.3.5 MODEL DATA INPUTS AND REFERENCES

This section lists the key commercial model inputs and provides a summary of their units, application, and data sources.

Table 9: Commercial Model Inputs

Title	Units	Description	Reference
Capacity:COM AC	kBTU/Sq. Ft.	Air conditioning capacity by final energy	CEUS, 2006. SCE values used for LADWP and "Other" electric service territories. Adjusted for square footage with no cooling.
Capacity:COM CK	BTU/Sq. Ft.	Cooking capacity share	CEUS, 2006.
Capacity:COM LT	Lumens/Sq. Ft.	Lumens per square foot	DOE Lighting Market Characterization Report, 2010.
Capacity:COM RF	kBTU/Sq. Ft.	Refrigeration capacity	CEUS, 2006. SCE values used for LADWP and "Other" electric service territories.
Capacity:COM SH	kBTU/Sq. Ft.	Space heating capacity by final energy	CEUS, 2006. SCE values used for LADWP and "Other" electric service territories.

Title	Units	Description	Reference
Capacity:COM VT	1000 CFM/Sq. Ft.	CFM per square feet	Wattage/Sq. Ft.: CEUS, 2006. CFM/W and Service demand share:Data used in support of AEO 2013 from the National Energy Modeling System: Input filename “ktek.xtxt'. "2007 Survey Base" technology.
Capacity:COM WH	kBTU/Sq. Ft.	Water heating capacity (kBTU) per Sq. Ft.	CEUS, 2006.
Data:COM OT Ele	GWh	Sectoral electricity demand input data	Energy Demand 2010-2020, Adopted Forecast, California Energy Commission, December 2009, CEC-200-2009-012-CMF
Data:COM OT Gas	Mtherms	Sectoral pipeline gas demand input data	IEPR 2014 - Mid Demand Case
Data:COM OT Oth	GDE	Sectoral "other" energy input data. Input	«null»
Ene Usage Tar:COM AC	GWh	Calibration energy usage target	Energy Demand 2010-2020, Adopted Forecast, California Energy Commission, December 2009, CEC-200-2009-012-CMF
Ene Usage Tar:COM CK	Mtherms	Calibration energy usage target	CEUS,2006. Extrapolated from Limited Statewide commercial building stock.
Ene Usage Tar:COM LT	GWh	Calibration energy usage target	Energy Demand 2010-2020, Adopted Forecast, California Energy Commission, December 2009, CEC-200-2009-012-CMF
Ene Usage Tar:COM RF	GWh	Calibration energy usage target	Energy Demand 2010-2020, Adopted Forecast, California Energy Commission, December 2009, CEC-200-2009-012-CMF

Title	Units	Description	Reference
Ene Usage Tar:COM SH	Therms	Calibration energy usage target	Total 2006 commercial gas usage from 2014 IEPR. Water heating share of commercial natural gas usage from CEUS, 2006.
Ene Usage Tar:COM VT	GWh	Calibration energy usage target	Energy Demand 2010-2020, Adopted Forecast, California Energy Commission, December 2009, CEC-200-2009-012-CMF
Ene Usage Tar:COM WH	Therms	Calibration energy usage target	Total 2006 commercial gas usage from 2014 IEPR. Water heating share of commercial natural gas usage from CEUS, 2006.
Stock Share:COM AC	% of Stock	Reference technology shares	Service demand share from National Energy Modeling System: Input filename “ktek.txt” adjusted for service saturation from 2006 CEUS.
Stock Share:COM BS	% of Stock	Reference technology shares	
Stock Share:COM CK	% of Stock	Reference technology shares	CEUS, 2006.
Stock Share:COM LT	% of Stock	Reference technology shares	DOE Lighting Market Characterization Report, 2010.
Stock Share:COM RF	% of Stock	Reference technology shares	Data used in support of AEO 2013 from the National Energy Modeling System: Input filenames “ktek.txt”.
Stock Share:COM SH	% of Stock	Reference technology shares	Data used in support of AEO 2013 from the National Energy Modeling System: Input filename “ktek.txt”. Adjusted for capacity share from CEUS, 2006.

Title	Units	Description	Reference
Stock Share:COM VT	% of Stock	Reference technology shares	Data used in support of AEO 2013 from the National Energy Modeling System: Input filenames “ktek.txt”.
Stock Share:COM WH	% of Stock	Reference technology shares	Data used in support of AEO 2013 from the National Energy Modeling System: Input filenames “ktek.txt”. Service demand shares. Represents service demand share for census division 9 (Pacific).
Tech Input:COM AC	«null»	Technology inputs including useful life, energy type, and cost assumptions	Data used in support of AEO 2013 from the National Energy Modeling System: Input filenames “ktek.txt”.
Tech Input:COM BS	«null»	Same as above.	Same as above.
Tech Input:COM CK	«null»	Same as above.	Same as above.
Tech Input:COM LT	«null»	Same as above.	Same as above. Useful life assumptions based on 4000 hrs per year (minimum lifetime of 1 year).
Tech Input:COM RF	«null»	Same as above.	Data used in support of AEO 2013 from the National Energy Modeling System: Input filenames “ktek.txt”.
Tech Input:COM SH	«null»	Same as above.	Same as above.
Tech Input:COM VT	«null»	Same as above.	Same as above.
Tech Input:COM WH	«null»	Same as above.	Same as above.

Title	Units	Description	Reference
UEC or DEM:COM AC	kWh/Sq Ft.	Subsector energy or service demand consumption estimate used to calibrate total service demand	CEUS, 2006.
UEC or DEM:COM CK	BTU/Sq. Ft.	Same as above.	CEUS, 2006.
UEC or DEM:COM LT	klumen-hrs/sq ft	Same as above.	DOE Lighting Market Characterization Report, 2010.
UEC or DEM:COM RF	kWh/Sq. Ft.	Same as above.	CEUS, 2006.
UEC or DEM:COM SH	BTU/Sq. Ft.	Same as above.	CEUS, 2006. SCE values used for LADWP and "Other" electric service territories.
UEC or DEM:COM VT	BTU/Sq. Ft.	Same as above.	CEUS, 2006.
UEC or DEM:COM WH	BTU/Sq ft.	Same as above.	CEUS, 2006.
Vintage Cost:COM AC	$/kBTU	Per-unit technology costs	Data used in support of AEO 2013 from the National Energy Modeling System: Input filenames "ktek.txt".
Vintage Cost:COM BS	$/Sq Ft	Same as above.	Same as above.
Vintage Cost:COM CK	$/kBTU	Same as above.	Same as above.
Vintage Cost:COM LT	$/1000 Lumens	Same as above.	Same as above.
Vintage Cost:COM RF	$/kBTU	Same as above.	Same as above.
Vintage Cost:COM SH	$/kBtu	Same as above.	Same as above.
Vintage Cost:COM VT	$/1000 CFM	Same as above.	Same as above.
Vintage Cost:COM WH	$/kBTU Out	Same as above.	Same as above.

Title	Units	Description	Reference
Vintage Eff:COM AC	BTU-out/BTU-in	Technology efficiencies	Same as above.
Vintage Eff:COM CK	Btu-out/BTU-in	Technology efficiencies	Same as above. Electric="Range, Electric, 4 burner, oven, 11" griddle" Gas="Range, Gas, 4 burner, oven, 11" griddle"
Vintage Eff:COM LT	klumens/kW	Technology efficiencies	Data used in support of AEO 2013 from the National Energy Modeling System: Input filename "ktek.txt."
Vintage Eff:COM RF	BTU-out/BTU-in	Technology efficiencies	Same as above.
Vintage Eff:COM SH	BTUout/BTUin	Technology efficiencies	Same as above.
Vintage Eff:COM VT	CFM-Out/BTU-in	Technology efficiencies	Same as above.
Vintage Eff:COM WH	BTU Out/BTU In	Technology efficiencies	Same as above.

2.4 Transportation

PATHWAYS' Transportation Module is used to project final transportation energy consumption, CO_2 emissions, and end-use equipment costs for the 9 transportation sectors consuming the 7 fuels listed in Table 10 and Table 11, respectively. Table 10 also indicates whether each subsector is modeled using calibrated *stock* turnover, where fuel usage is calculated as the sum of fuels used by the changing vehicle stock providing forecast Vehicle Miles Traveled (VMT), or using California forecasts of *fuel* demand (extended to 2050 using regression where required), with individually specified measures directly altering the trajectory of fuel demand over time.

Table 12 details the fuels used by each vehicle type (for stock subsectors) or subsector.

Table 10. Transportation subsectors

Subsector	Model type
Light duty vehicles (LDV)	Stock
Medium duty vehicles (MDV)	Stock
Heavy duty vehicles (HDV)	Stock
Busses (BU)	Stock
Aviation (AV)	Fuel
Passenger Rail (PR)	Fuel
Freight Rail (FR)	Fuel
Ocean Going (OG)	Fuel
Harbor Craft (HC)	Fuel

Table 11. Transportation fuels

Fuels
Electricity
Gasoline
Diesel
Liquefied Pipeline Gas (LNG)
Compressed Pipeline Gas (CNG)
Hydrogen
Kerosene-Jet Fuel

Table 12. Fuel Use by Vehicle Type

Vehicle Type	Name	Fuel(s)
Light duty auto	Reference Gasoline LDV	Gasoline
Light duty auto	PHEV25	Electricity, Gasoline
Light duty auto	BEV	Electricity
Light duty auto	Hydrogen Fuel Cell	Hydrogen
Light duty auto	Reference Gasoline LDV	Gasoline
Light duty truck	PHEV25	Electricity, Gasoline
Light duty truck	BEV	Electricity
Light duty truck	Hydrogen Fuel Cell	Hydrogen
Motorcycle	Reference Gasoline LDV	Gasoline
Motorcycle	PHEV25	Electricity
Motorcycle	BEV	Electricity
Motorcycle	Hydrogen Fuel Cell	Hydrogen
Medium duty	Baseline MDV-Gasoline	Gasoline
Medium duty	Reference MDV-Gasoline	Gasoline
Medium duty	Reference MDV-Diesel	Diesel
Medium duty	CNG MDV	Compressed Pipeline Gas (CNG)
Medium duty	Diesel Hybrid MDV	Diesel
Medium duty	Battery Electric MDV	Electricity
Medium duty	Hydrogen FC MDV	Hydrogen
Heavy Duty	Reference Diesel HDV	Diesel
Heavy Duty	Reference CNG HDV	Compressed Pipeline Gas (CNG)
Heavy Duty	Hybrid Diesel HDV	Diesel
Heavy Duty	Hydrogen FCV HDV	Hydrogen
Bus	Gasoline Bus	Gasoline
Aviation	N/A	Kerosene (Jet Fuel)
Ocean Going	N/A	Diesel, Electricity (In port)
Harbor Craft	N/A	Diesel, Electricity
Passenger Rail	N/A	Electric, Diesel
Freight Rail	N/A	Diesel

2.4.1 MODEL SUMMARY

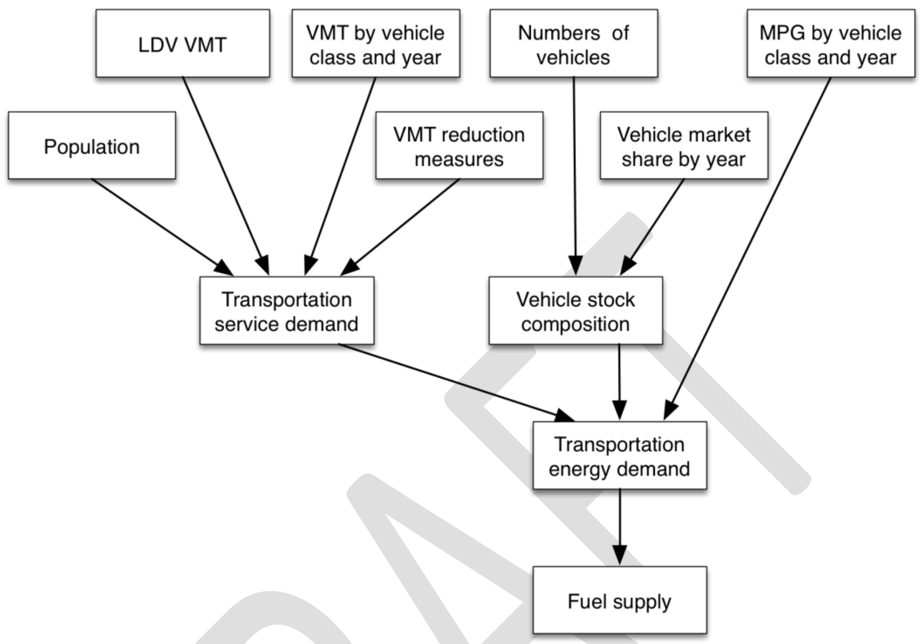
Table 13 summarizes key data sources for the transportation module. Based on the character of best available data, the Transportation Module uses a mixture of stock accounting (for on-road vehicles) and regression-extended state forecasts of fuel consumption (for off-road vehicles).

Table 13: Summary of transportation module data sources

Category	Data Source
VMT/Fuel use	• CARB EMFAC 2011 (LDV, MDV, HDV, and Buses) • ARB Vision off-road (passenger rail, freight rail, harbor craft, oceangoing vessels, aviation)
Fuel efficiency	• CARB EMFAC 2011 (MDV, HDV, Buses, LDV motorcycles) • "Transitions to Alternative Vehicles and Fuels", National Academies Press, 2013, Mid case (LDV auto and truck) • ARB Vision off-road (passenger rail, freight rail, harbor craft, oceangoing vessels, aviation)
New Technology	• "Transitions to Alternative Vehicles and Fuels", National Academies Press, 2013 • Assessment of Fuel Economy Technologies for Medium- and Heavy-Duty Vehicles • 2012 MODEL YEAR ALTERNATIVE FUEL VEHICLE (AFV) GUIDE • Department of Transportation Fuel Cell Bus Life Cycle Model: Base Case and Future Scenario Analysis • "Zero Emissions Trucks." Delft, 2013 • "Advancing Technology for America's Transportation Future." National Petroleum Council, 2012.
Emissions	• EPA emission factors • CARB refining fuel combustion emissions • APTA 2010 Fact Book, Appendix B

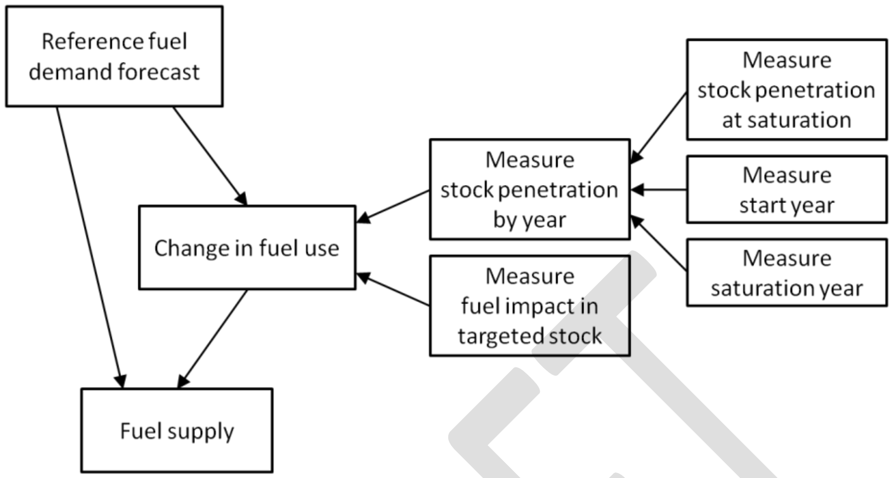
For stock sub-sectors, (i.e. LDVs, MDVs, HDVs, and Buses), transportation service demand (i.e. VMT) and total vehicle counts are based on linear extrapolation out to 2050 of CARB EMFAC 2011 data, which contain historical data and forecasts to 2035. The drivers of transportation fuel demand in stock sectors are illustrated in Figure 5 using LDVs as an example.

Figure 5. Drivers of transportation fuel use for stock modeled sub-sectors, using light duty vehicles for illustration.



For fuel-only sectors, i.e. passenger rail, freight rail, harbor craft, oceangoing vehicles, and aviation, reference fuel consumption is based on a linear fit of forecasts from the CARB VISION off-road model. The drivers of fuel demand in fuel-only sub-sectors are illustrated in Figure 6.

Figure 6: Drivers of transportation fuel use for fuel modeled sub-sectors.



This section provides an overview of the stock-rollover sub-sector calculations (Section 2.4.3) and fuel use sub-sector calculations (Section 2.4.4) at the heart of the Transportation Sector Module. It also details the calculation of CO_2 emissions (Section 2.4.5) and transportation energy system costs (Section 2.4.6).

2.4.2 MEASURES

Measures specify the timing and magnitude of deviations from the reference case caused by mitigation efforts over time. The stock modeled sub-sectors of the Transportation Module capture changing market share, rollover (retirement), and replacement of vehicles over time. Stock growth and replacement — new stock — provides an opportunity for vehicle efficiency improvements and fuel switching. Users reduce transportation CO_2 emissions in PATHWAYS by implementing measures that reduce VMT or change the characteristics of the deployed vehicle stock over time.

The fuel-only sub-sectors of the Transportation Module use CA forecasts of fuel demand, extrapolated to 2050 using linear regression. For these sub-sectors, users implement aggregate energy efficiency and fuel switching measures that lead directly to percentage changes in the amount and type of fuels consumed by the vehicles in a particular subsector. These measures directly modify the reference forecast of transportation fuel demand. In the fuel-only subsectors, rates of measure roll outs are constrained to reflect expected stock lifetimes.

There are three types of measures that impact different drivers of emissions in the Transportation Module.

1. **Service demand change measures** reduce VMT for specific stock modeled vehicle types. Measures of this type are used to model actions that reduce driving, for example, Smart Growth and transit oriented development can reduce VMT in cars.
2. **Stock measures** change the relative portion of each vehicle type (i.e. plug-in hybrids (PHEVs), fuel cell vehicles (FCVs), battery electric vehicles (BEVs), more efficient internal combustion vehicles (ICEs), etc.) sold from one year to the next. Measures of this type are used to model the timing and magnitude of market adoption of new technologies and vehicle types, like PHEVs and BEVs and market declines of older vehicle technologies, like conventional ICEs.
3. **Aggregate measures** directly reduce demand for specific fuels in fuel-based sub-sectors. Measures of this type are used to model the fuel impacts of market adoption of vehicle technologies, (e.g. electric light rail, fuel switching, powering ships with electricity while in port, and operational changes, flying fewer but larger planes or slow steaming in

shipping). Typically the percentage change in fuels specified in aggregate measures are based on side calculations using the best available information on potential savings.

2.4.3 TRANSPORTATION STOCK-ROLLOVER SUB-SECTORS

The Transportation Module includes a stock-rollover mechanism that governs changes in on-road (LDV, MDV, and HDV) vehicle stock composition, fuel economy, fuel switching opportunities, and vehicle costs over time. The mechanism tracks vehicle vintage — the year in which a vehicle was purchased — by vehicle sub-category and air quality district, the latter being the standard geographic breakdown of the source data from CARB.

At the end of each year, PATHWAYS retires some amount of a given vehicle type in a given region ($S.RET_y$), by multiplying the initial stock of each vintage (S_{vy}) by a replacement coefficient (β_{vy}).

Equation 38

$$S.RET_y = \sum_{v}^{y} S_{vy} \times \beta_{vy}$$

New Subscripts

y	year	is the model year (2010 to 2050)
v	vintage	is the vehicle vintage (1950 to year y)

New Variables

$S.RET_y$	is the amount of existing stock of vehicles retired in year y
$S.EXT_{vy}$	is the existing stock of vehicles with vintage v in year y
β_{vy}	is a replacement coefficient for vintage v in year y

The replacement coefficients are generated by a survival function that uses Poisson distribution, with a mean, λ, equal to the expected useful life of each vehicle category. For example, light duty autos have a λ=17.

Equation 39

$$\beta_{vy} = e^{-\lambda} \frac{\lambda^{y-v+1}}{(y-v+1)!}$$

The Poisson distribution has a right-skewed density function, which becomes more bell-shaped around λ at higher λ values. This approach is analogous to the application of a Weibull function for survival rates of end use technologies in the NEMS building sectors. Survival functions, both in PATHWAYS and NEMS, are a significant source of uncertainty. Given the long timeframe for this analysis, the choice of survival function distribution affects the timing of the results, but not the ability to meet a 2050 target.

At the beginning of the following year (y+1), PATHWAYS replaces retired stock and adds new stock to account for forecasted growth in the vehicle stock. The vintage of these new stock additions is then indexed to year y+1.

Equation 40

$$S.NEW_{y+1} = S.RET_y + S.GRW_y$$

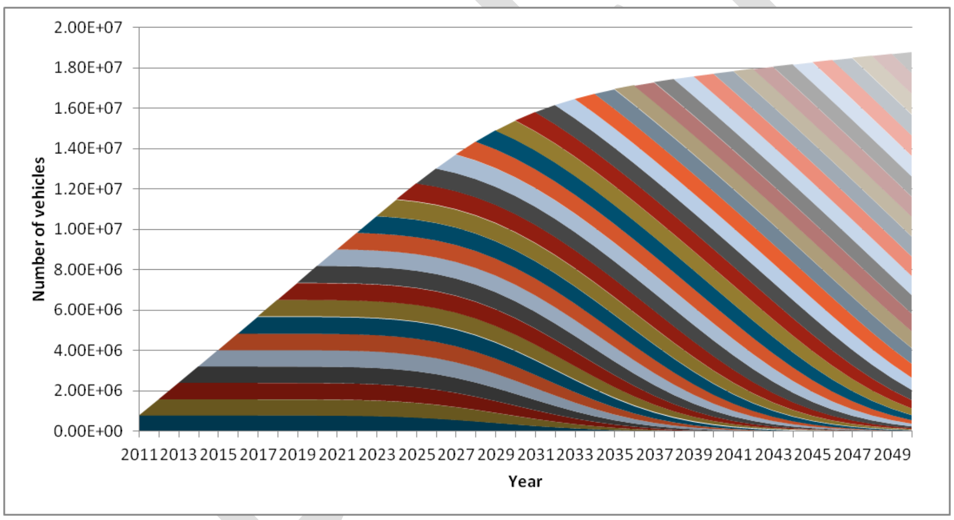
We use this stock-rollover process to determine the composition of both the existing (pre-2010) and future (2011-2050) stock of vehicles. Different vehicle technologies can have different primary (and optional secondary) fuel types, useful life (years), fuel economy (Miles/GGE), and cost. Across vehicle types, fuel economy increases with vintage to reflect incremental technological progress.

A simple example facilitates understanding of how the stock-rollover process drives changes in stock composition and vintage. Consider a region that has 1000 standard light duty autos in 1999. All autos have an expected 17-year lifetime. Assume all of the autos were sold in 1990. At the end of 1999, the replacement coefficient will be 0.023,[11] indicating that 23 autos (=1000 * 0.023) will be retiring at year's end. Assume, for illustration, that all 23 of these autos will be replaced with hybrids and there is no growth in the vehicle stock. This means that, in year 2000, there will be 1000 autos (= 1977 standard +23 hybrid). In 2000, hybrids account for 2.3% of the light duty auto stock, an increase from 0% in 1999. All 23 autos that are replaced in 2000 will have a 2000 vintage.

[11] With an expected useful life of 17 years, the replacement coefficients for 10-year (i.e., sold in 1990) old vehicles are $e^{-17}\frac{17^{10}}{10!} = 0.023$.

The stock roll over for light duty autos is illustrated in Figure 7. Each wedge in the figure represents a vehicle vintage, and each wedge narrows and eventually declines to zero as the entire vintage is retired. For instance, the 2013 vintage has completely turned over by the early 2030s. The shape of the stock of these vehicles (i.e., the aggregate curve) is governed by adoption saturation, described in greater detail in Section 2.4.3.4.

Figure 7. Illustration of stock-rollover process for light duty cars. Each colored band represents a different vintage, with vintages ranging from 2011 to 2050. Vintages prior to 2011 are not shown, but would be present in the actual stock.



2.4.3.1 Stock Final Energy Consumption

PATHWAYS calculates transportation stock final energy consumption (T.SEC) of different final energy types in each year as the product of two main terms: (1) district-, vehicle-type-, and vintage-specific VMT and (2) vehicle fuel economy that is weighted by the market share for a given vintage of a given type of equipment in a district (e.g., the share of 2020 vintage battery electric vehicles in the total number of vehicles in the SCAQMD district in 2025).

Equation 41

$$T.SEC_{ey} = \sum_{i}\sum_{k}\sum_{m}\sum_{v} ACT_{imy} \times ESD_{mvy} \times \frac{MKS_{imvey}}{EFF_{mvey}}$$

New Subscripts

e	final fuel type	electricity, gasoline, diesel, liquefied pipeline gas (LNG), compressed pipeline gas (CNG), hydrogen
y	year	model year (2010 to 2050)
i	air quality district	SJVAPCD, SCAQMD, Other
k	vehicle category	LDV, MDV, HDV, Buses
m	vehicle sub-category	vehicle sub-categories (i.e. auto, truck, motorcycle in LDV)
v	vintage	vehicle vintage (1950 to year y)

New Variables

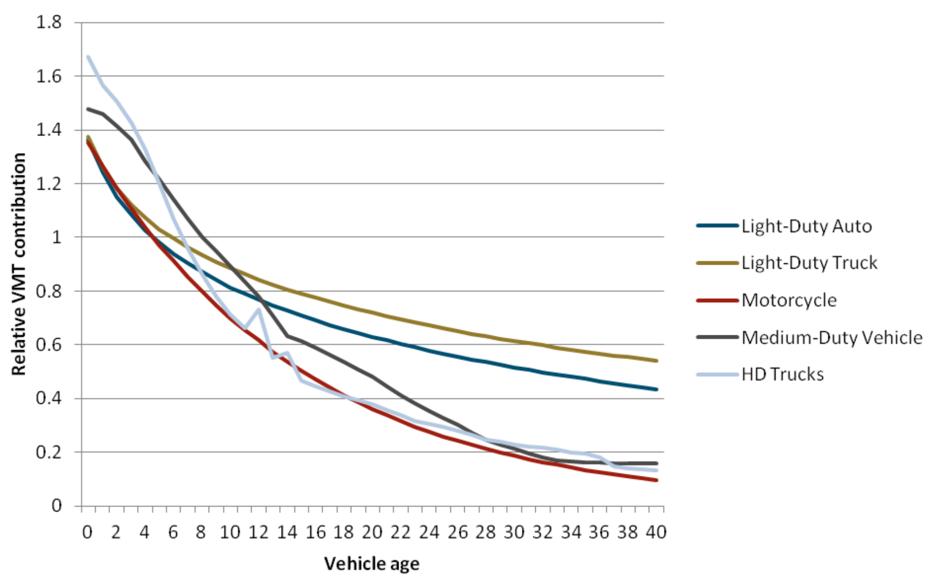
$T.SEC_{ey}$	is transportation stock final energy consumption of final fuel type e in year y
ACT_{imvy}	is VMT per vehicle sub-category m per vintage v per air quality district i in year y
ESD_{iky}	is vehicle fuel economy per vehicle sub-category m per vintage v in year y
MKS_{imvey}	is the market share for vintage v of vehicle sub-category m consuming fuel type e in air quality district i in year y
EFF_{mvey}	is the energy efficiency of vintage v of vehicle sub-category m consuming final fuel type e in year y

2.4.3.2 Service Demand

The Transportation Sector Module’s units of service demand are Vehicle Miles Traveled (VMT), segmented by air quality district, vehicle sub-type, and vehicle age.[12] Reference VMT is based on the CARB EMFAC 2011 forecast to 2035, with a linear extrapolation from 2035 to 2050.

Figure 8 illustrates the impact vehicle age has on VMT by vehicle sub-type - the basic relationship is that the older a vehicle is, the less it is assumed to be driven.

Figure 8: Relative VMT contribution from vehicles of different ages for different vehicle sub-types



[12] Vehicle VMT is adjusted by age (year - vintage) to reflect different driving patterns for newer and older vehicles.

2.4.3.3 Vehicle Counts

Total vehicle counts by air quality district and vehicle sub-category are based on the CARB EMFAC 2011 forecast to 2035, with a linear extrapolation from 2035 to 2050. We project future vehicle types using the stock-rollover approach described in Sections 2.4.3 and 2.4.4, which defaults to replacing retiring vehicles with new vehicles of the same fuel type, but allows for changes in vehicle fuel type, fuel economy, costs, and vintage over time.

Equation 42: total vehicle counts

$$TV_{ijy+1} = \sum_{v}^{y} TV_{vijy} \times (1 - \beta_{vy}) + (TV_{vijy} \times \beta_{vy} + NV_{ijy+1}) \times \theta_{ijy}$$

New Variables

TV_{ijy+1}	is the number of vehicles of type j in air quality district i in year y+1
TV_{vijy}	is the number of vehicles of vintage v and type j in air quality district i in year y
NV_{ijy}	is the number of new vehicles of type j in air quality district i in year y+1
θ_{ijy}	is the share of vehicle type j in total vehicles in year y

The replacement coefficients (β) are based on an expected lifetimes (17 years for LD autos and trucks, 10 for motorcycles, 17 for MDVs, and 16 for HDVs) for vehicles, where “lifetime” is more precisely defined as the mean time before retirement, or λ in the Poisson distribution used to determine retirement fractions.

2.4.3.4 Vehicle Measures, Adoption, and Market Shares

PATHWAYS reduces stock transportation CO_2 emissions relative to a reference case through measures that change the composition of new vehicles. Users implement transportation stock measures in PATHWAYS by selecting vehicle-specific adoption curves. Adoption of new vehicles leads to changes in market share for a given vintage and type of vehicle over time.

In PATHWAYS, turnover of existing stock and new stock growth drive sales of new vehicles. In the reference case, sales penetration for a given type of vehicle — its share of new sales — is based on the reference case. Users change reference case sales penetrations by choosing the level and approximate timing of saturation for a given type of vehicle (e.g., new sales of battery electric autos saturate at 30% of total new auto sales in 2030). PATHWAYS allows the user to choose between linear and S-shaped adoption curves. In the main scenarios, sales penetrations (SPN) for most vehicle types are based on aggregated S-shaped curves

Equation 43

$$SPN_{mvey} = \frac{SAT_{me}}{1 + \propto^{x}}$$

where x is a scaling coefficient that shifts the curve over time based on a user defined measure start year and time-to-rapid-growth (TRG) period (in years).

Equation 44

$$x = \frac{MSY_{me} + TRG_{me} - y}{TRG_{me}}$$

and TRG is calculated as

Equation 45

$$TRG_{me} = \frac{ASY_{me} - MSY_{me}}{2}$$

New Variables

SPN_{mvey}	is the sales penetration of vintage v of vehicle type m using final energy type e in year y
SAT_{me}	is the saturation level of vehicle type m using final energy type e
α	is a generic shape coefficient, which changes the shape of the S-curve
MSY_{me}	is the measure start year for vehicle type m using final energy type e in a specified year
TRG_{me}	is the time-to-rapid-growth for adoption of vehicle type m using final energy type e in a specified year
ASY_{me}	is the approximate saturation year for adoption of vehicle type m using final energy type e

Market shares for a vehicle of a specific vintage in a given year are the initial stock of that vintage (determined by the adoption curve) minus the stock that has turned over and been replaced, divided by the total stock of vehicles in that year (e.g., the share of 2020 vintage battery electric autos in the total stock of autos in 2025).

Equation 46

$$MKS_{mvey+1} = \frac{EQP_{vme} - \sum_{v}^{y} EQP_{vme} \times \left(1 - \beta_{vy}\right)}{EQP_{y+1}}$$

New Variables

MKS_{mvey+1}	is the market share of vintage v of vehicle type m using final energy type e in year y+1
EQP_{vme}	is the stock of vehicles adopted of vehicle type m using final energy type e with vintage v
EQP_{y+1}	is the total stock of vehicles in year y+1

If total sales of new vehicles exceed sales of user-determined measures (i.e., if the share of measures in new sales is less than 100% in any year), adoption of residual vehicles is assumed to match that in the reference case. In cases where adoption may be over-constrained, PATHWAYS normalizes adoption saturation so that the total share of user-determined measures in new sales never exceeds 100% in any year.

Given the large number of potential measures, vehicle adoption in PATHWAYS is generally not done by air quality district. Instead, vehicles are regionalized through equipment ownership, which is determined separately for each district. This assumption is consistent with state-wide policies, and is important for understanding the district-level results.

2.4.4 TRANSPORTATION FUEL-ONLY SUB-SECTORS

The Transportation Module includes fuel-only accounting of energy use for off-road vehicles (aviation, passenger rail, freight rail, oceangoing vessels, harbor craft) where fuel use forecasts provide the best available data. For these subsectors, the reference scenario fuel consumption data is pulled from the CARB VISION model, with a linear extrapolation to 2050 performed via regression models.

2.4.4.1 Fuel-only Measures

In fuel-only sub-sectors, scenarios alter reference trajectories for transportation fuel consumption using measures that directly alter transportation fuel consumption. Within each sub-sector, fuel-only measures consist of several attributes, which are detailed in Table 14.

Table 14: Attributes of fuel-only "aggregate" measures

Attribute	Description
Impacted Stock	The fraction of stock impacted by the measure in the saturation year
Replacement Fuel	The fuel used after the measure
Impacted Fuel	The fuel impacted by the measure
EE Improvement	The fraction of reference scenario fuel use eliminated within the impacted stock
Start Year	The year when the first impacts of the measure are first achieved
Saturation Year	The year when the measure impacts reach their full potential
Levelized Cost	The cost of the measure levelized across energy saved in $/Demand Unit

Between the start year and the saturation year, measure impacts follow a linear ramp until they save the full EE Improvement for the full impacted stock. If the impacted fuel and replacement fuels are the same, then the aggregate measure changes the consumption of that single fuel, as would be expected for either service demand (VMT) or vehicle efficiency (VMT/fuel) changes.

Equation 47: Fraction of stock impacted

$$FSI_{jmey} = max\left(min\left(\frac{y_{sat} - y}{y_{sat} - y_{start}}, 1\right), 0\right) \times SF_{jme}$$

New Variables

FSI_{jmey}	fraction of stock impacted per measure m per vehicle type j per fuel type e in year y
y_{sat}	saturation year
y_{start}	measure start year
SF_{jme}	"stock fraction" by measure m per vehicle type j per fuel type e in the saturation year
ECI_{jme}	fractional energy change in impacted stock (aka EE Improvement) per measure m per vehicle type j per fuel type e

Note that the saturation calculation is forced by the *max* and *min* functions to fall within limits of 0 and 1, representing the period prior to implementation and the period after complete saturation, respectively.

2.4.4.1.1 Energy Efficiency and Fuel Switching

Before the fuel energy change associated with efficiency can be calculated, fuel switching must be accounted for. The fuel energy impacted, FEI, is the energy consumption impacted by a given measure and is subtracted from the impacted fuel and added to the replacement fuel. Thus it has no impact when the impacted and replacement fuels are the same.

Equation 48: Fuel switched

$$FEI_{jmey} = \sum_i FSI_{jmey} \times REF_{ijey} \times EF_{jme}$$

New Variables

FEI_{jmey}	fuel energy impacted per measure m per vehicle type j per fuel type e in year y
REF_{ijey}	Reference energy consumption per vehicle type j per fuel type e per service territory i in year y
EF_{jme}	"energy fraction" altered per measure m per vehicle type j per fuel type e in the saturation year

The "fuel energy replaced" (**FER**) is the "fuel energy impacted" (**FEI**) adjusted for any efficiency change described by the measure.

Equation 49: Replaced fuel energy

$$FER_{jmey} = \sum_i FEI_{jmey} \times (1 - EEI_{jme})$$

New Variables

FER_{mefy}	replaced fuel energy per measure m per vehicle type j per fuel type e in year y
EEI_{mef}	energy efficiency improvement per measure m per fuel type e per vehicle type j

Equation 50: Fuel-only transportation energy

$$T.FEC_{ey} = \sum_{j}\left(\sum_{i} REF_{ijey} + \sum_{m} -FEI_{jmey} + FER_{jmey}\right)$$

New Variables

$T.FEC_{ey}$	Fuel-only energy consumption for fuel type e in year y

2.4.5 CO_2 EMISSIONS

We calculate total CO_2 emissions from the transportation sector in each year as the sum product of final energy consumption (itself the sum of final stock energy consumption from on-road vehicles and final fuel energy consumption from off-road vehicles) and a CO_2 emission factor.

Equation 51: Transportation CO_2 emissions

$$T.CO2_{y} = \sum_{e}\left((T.SEC_{ey} + T.FEC_{ey}) \times CEF_{ey}\right)$$

Variables

$T.CO2_{y}$	is transportation CO_2 emissions in year y
$T.SEC_{ey}$	is the final stock energy (i.e. on-road) for energy type e in year y
$T.FEC_{ey}$	is the final fuel-only energy (i.e. off-road) for energy type e in year y
CEF_{ey}	CEF_{ey} is a CO_2 emission factor for energy type e, which can vary by year for energy carriers, like pipeline gas.

All CO_2 emission factors for primary energy are based on higher heating value (HHV)-based emission factors used in AEO 2013. CO_2 emission factors for energy carriers are calculated and described in the Energy Supply sections.

2.4.6 ENERGY SYSTEM COSTS

Energy system costs are defined in PATHWAYS as the incremental capital and energy cost of measures. The incremental cost of measures is measured relative to a reference technology, which is based on vehicles that were adopted (stock), measure implementation costs (fuels only), and fuels consumed in the reference case.

2.4.6.1 Capital Costs

PATHWAYS calculates end use capital (vehicle efficiency) costs by vintage on an annualized ($/yr) basis, where annual transportation vehicle costs (T.AQC) are the total transportation vehicle cost (T.TQC) multiplied by a capital recovery factor (CRF) plus the annualized costs of non-stock measures (T.AMC).

Equation 52: Annual vehicle costs

$$T.AQC_{mv} = T.TQC_{mv} \times CRF$$

Equation 53: Capital recovery factor

$$CRF = \frac{r}{[1-(1+r)^{-EUL_m}]}$$

Variables

$T.AQC_{mv}$	is the annual vehicle cost for vintage v of vehicle type m
$T.TQC_{mv}$	is the total vehicle cost for vintage v of vehicle type m
r	is a time, vehicle type, district invariant discount rate
EUL_m	is the expected useful life of vehicle type m

PATHWAYS uses a discount rate of 10%, approximating the historical average of real credit card interest rates.[13] This discount rate is not intended to be a hurdle rate, and is not used to forecast technology adoption. Rather, it is meant to be a broad reflection of the opportunity cost of capital to vehicle owners.

Consistent with our stock-rollover approach to adoption and changes in the vehicle stock, we differentiate between the cost of vehicles that are replaced at the end of their expected useful life ("natural replacement"), and vehicles that are replaced before the end of their useful life ("early replacement"). The incremental cost of vehicles that are naturally replaced is the annual cost of the vehicles minus the annual cost of vehicles used in the reference case.

[13] From, 1974 to 2011, the CPI-adjusted annual average rate was 11.4%. Real rates are calculated as $r^R = \frac{(1+r^N)}{(1+i)} - 1$, where i is a rate of consumer inflation based on the CPI. Nominal credit card interest rates are from Board of Governors of the Federal Reserve System, "Report to the Congress on the Profitability of Credit Card Operations of Depository Institutions," June 2012, http://www.federalreserve.gov/publications/other-reports/credit-card-profitability-2012-recent-trends-in-credit-card-pricing.htm. Historical CPI data are from Bureau of Labor Statistics, "CPI Detailed Report Tables," June 2014, http://www.bls.gov/cpi/cpid1406.pdf.

Equation 54: Incremental equipment costs

$$T.IQC_{mv} = T.AQC_{mv} - T.AQC'_{mv}$$

New Variables

$T.IQC_{mv}$	is the incremental annual transportation vehicle equipment cost for vehicle type m
$T.AQC_{mv}$	is the annual cost for vehicle type m that consumes final energy type e for a given scenario examined in this report
$T.AQC'_{mv}$	is the annual vehicle cost for vehicle type m that consumes final energy type e for the reference case

For vehicles, early replacement measures are assessed the full technology cost and do not include any salvage value. We calculate total incremental transportation vehicle costs in year y as the sum of annual incremental costs across vintages and vehicle types.

Equation 55: Total incremental cost of vehicles

$$T.IQC_y = T.AMC_y + \sum_m \sum_v^y T.IQC_{mv}$$

New Variables

$T.IQC_y$	is the total incremental cost of vehicles in year y
$T.AMC_y$	is the annual measure implementation cost for non-stock measures

2.4.6.2 Fuel-Only Measure Costs

For fuel-only (i.e., non-fuel switching) measures, energy efficiency costs are the product of measure-specific reductions in final energy and the measure-specific levelized cost of implementation (LC).

Equation 56: Annualized fuel-only measure costs

$$T.FMC_y = \sum_e \sum_m \left(\sum_j FEI_{jmey} \times LC_m \right)$$

New Variables

$T.FMC_y$	Fuel-only aggregate measure costs in year y
LEC_m	Input levelized costs for measure m

2.4.6.3 Energy Costs

Annual transportation energy costs (T.AEC) in PATHWAYS are calculated by multiplying final energy consumption for each final energy type in each year ($T.SEC_{ey}$+$T.FEC_{ey}$) by a unit energy price (P) in that year.

Equation 57: Annual energy costs

$$T.AEC_{ey} = (T.SEC_{ey} + T.FEC_{ey}) \times P_{ey}$$

New Variables

$T.AEC_{ey}$	is the total annual transportation energy cost for final energy type e in year y
P_{ey}	Is the unit price of final energy type e in year y

Electricity prices are calculated through the Electricity Sector Module, described in the Electricity section. Non-electricity (e.g., pipeline gas) prices are calculated in supply side fuels module and received by the Transportation module as inputs. Incremental annual transportation energy costs are calculated relative to the Reference scenario.

Equation 58: Incremental energy costs

$$T.IEC_{ey} = T.AEC_{ey} - T.AEC'_{ey}$$

New Variables

$T.IEC_{ey}$	is the total incremental annual transportation energy cost for final energy type e in year y
$T.AEC'_{ey}$	is the total annual transportation energy cost for final energy type e in year y in the reference case

2.4.6.4 Total Annual Costs

Total annual transportation costs are the sum of levelized incremental equipment costs (on-road), levelized measure costs (off-road), and incremental fuel costs.

Equation 59. Total annual costs

$$T.AIC_y = T.IQC_y + T.FMC_y + \sum_e T.IEC_{ey}$$

New Variables

$T.AIC_y$	is the transportation annual incremental costs for a scenario in year y

2.4.7 EXAMPLE MEASURES

This section provides examples of transportation measure definitions from all three categories of measures with a discussion of the real world goals the measures seek to replicate.

Table 15 presents a typical package of stock measures designed to apply to light duty autos. Together, these measures dramatically reduce the number of reference internal combustion vehicles. Starting in 2013, ICEs are replaced by plug-in hybrids, reaching 30% of sales in 2028. Starting in 2020, battery electric vehicles and hydrogen fuel cell vehicles also start replacing ICEs. By 2030, battery electric vehicles also start replacing plug-in hybrids. The end result is a vehicle population that is mostly Hydrogen Fuel Cells and BEVs by 2050, with small residual numbers of ICEs and PHEVs.

Table 15: Example Stock Measures for Light Duty Autos

Technology	Technology Replaced	Start Year	Sat. Year	Stock Fraction	Penetration Shape
PHEV25	Reference Gasoline ICE	2013	2028	0.3	S-Curve
BEV	PHEV25	2030	2035	0.3	Linear
Reference Gasoline ICE	Reference Gasoline ICE	2035	2050	0.1	Linear
BEV	Reference Gasoline ICE	2020	2035	0.3	Linear
Hydrogen Fuel Cell	Reference Gasoline ICE	2020	2045	0.7	Linear

Table 16 presents a typical demand change measure related to VMT reductions achieved through smart growth as modeled in CARB's VISION model. That model predicts a 20% reduction in VMT by 2050, so this measure starts reducing VMT in 2015, with a linear ramp saturating at 20% in 2050.

Table 16: Example demand change measures for light duty vehicles

Measure Name	Demand Change	Start Year	Sat. Year
ARB Vision Scenario 3 VMT reduction	0.2	2015	2050

Table 17 presents typical aggregate measures impacting aircraft and ocean going vessels. The first measure is the total efficiency potential estimated by the final report for the FAA's TAPS II Combustor CLEEN project, which is a 70% reduction in fuel use by 2050. The second aggregate measure describes fuel switching where 80% of ocean going vessels can be converted to use grid power in port, rather than running their fuel powered generators. This measure performs fuel switching from Diesel to Electricity and accomplishes a 45% reduction in total energy due to efficiencies from electrification. The final aggregate measure is based on the International Marine Organization's Energy Efficiency Design Index, which estimates an aggregated 40% fuel savings potential from improved hull design, larger ships, more efficient propulsion, slow steaming, and related efforts.

Table 17: Example aggregate measures for aircraft and ocean vessels

Sector	Measure Name	Stock fraction	Replacement Fuel	Impacted Fuel	EE % increase	Start Year	Sat. Year
Aircraft	FAA CLEEN CO2	1	Kerosene-Jet Fuel	Kerosene-Jet Fuel	0.7	2013	2050
Ocean Vessel	Shore Power	0.8	Electricity	Diesel	0.45	2020	2050
Ocean Vessel	EEDI Efficiency Requirements	1	Diesel	Diesel	0.4	2013	2050

2.4.8 KEY INPUT VARIABLES AND SOURCES

Table 18: Key transportation input variables

Variable	Title	Units	Description	Reference
Data_TRA _AV_Ele	Data:TRA AV Ele	GWh	Sectoral electricity demand input data	CARB VISION off road model: http://www.arb.ca.gov/planning/vision /docs/arb_vision_offroad_model.xlsx
Data_TRA _AV_Gas	Data:TRA AV Gas	Mtherms	Same as above	Same as above
Data_TRA _AV_Oth	Data:TRA AV Oth	BTU	Sectoral "other" energy input data. Input	Same as above
Data_TRA _FR_Ele	Data:TRA FR Ele	GWh	Sectoral electricity demand input data	Same as above
Data_TRA _FR_Gas	Data:TRA FR Gas	Mtherms	Sectoral pipeline gas demand input data	Same as above
Data_TRA _FR_Oth	Data:TRA FR Oth	GDE	Sectoral "other" energy input data. Input	Same as above
Data_TRA _HC_Ele	Data:TRA HC Ele	GWh	Sectoral electricity demand input data	Same as above
Data_TRA _HC_Gas	Data:TRA HC Gas	Mtherms	Sectoral pipeline gas demand input data	Same as above
Data_TRA _HC_Oth	Data:TRA HC Oth	GDE	Sectoral "other" energy input data. Input	Same as above
Data_TRA _OG_Ele	Data:TRA OG Ele	GWh	Sectoral electricity demand input data	Same as above
Data_TRA _OG_Gas	Data:TRA OG Gas	Mtherms	Sectoral pipeline gas demand input data	Same as above
Data_TRA _OG_Oth	Data:TRA OG Oth	GDE	Sectoral "other" energy input data. Input	Same as above

Variable	Title	Units	Description	Reference
Data_TRA_PR_Ele	Data:TRA PR Ele	GWh	Sectoral electricity demand input data	Same as above
Data_TRA_PR_Gas	Data:TRA PR Gas	Mtherms	Sectoral pipeline gas demand input data	Same as above
Data_TRA_PR_Oth	Data:TRA PR Oth	GDE	Sectoral "other" energy input data. Input	Same as above
Tech_Input_TRA_BU	Tech Input:TRA BU	«null»	Technology inputs including useful life, energy type, and cost assumptions	National Transit Database, Federal Transit Administration, 2011; AQMD Emissions Factors: http://www.aqmd.gov/trans/ab2766/ab2766_emission_factors.pdf; 2013 APTA Vehicle Database; Department of Transportation Fuel Cell Bus Life Cycle Model: Base Case and Future Scenario Analysis http://www.rita.dot.gov/sites/default/files/publications/fuel_cell_bus_life_cycle_cost_model/excel/appendix_a.xls
Tech_Input_TRA_HD	Tech Input:TRA HD	«null»	Technology inputs including useful life, energy type, and cost assumptions	CARB EMFAC 2011; Assessment of Fuel Economy Technologies for Medium- and Heavy-Duty Vehicles: http://www.nap.edu/catalog.php?record_id=12845
Tech_Input_TRA_LD	Tech Input:TRA LD	«null»	Technology inputs including useful life, energy type, and cost assumptions	CARB EMFAC 2011; ARB LDV Off-Road Model; "Transitions to Alternative Vehicles and Fuels", National Academies Press, 2013
Tech_Input_TRA_MD	Tech Input:TRA MD	«null»	Technology inputs including useful life, energy type, and cost assumptions	CARB EMFAC 2011; Assessment of Fuel Economy Technologies for Medium- and Heavy-Duty Vehicles: http://www.nap.edu/catalog.php?record_id=12845

Variable	Title	Units	Description	Reference
UEC_or_DEM_TRA_BU	UEC or DEM:TRA BU	VMT/Capita	Subsector energy or service demand consumption estimate used to calibrate total service demand	CARB EMFAC 2011
UEC_or_DEM_TRA_HD	UEC or DEM:TRA HD	VMT/Capita	Subsector energy or service demand consumption estimate used to calibrate total service demand	CARB EMFAC 2011
UEC_or_DEM_TRA_LD	UEC or DEM:TRA LD	VMT/Capita	Subsector energy or service demand consumption estimate used to calibrate total service demand. This is a calculated variable built off a regression of VMTs by AQMD divided by a population projection by AQMD.	CARB EMFAC 2011
UEC_or_DEM_TRA_MD	UEC or DEM:TRA MD	VMT/Capita	Subsector energy or service demand consumption estimate used to calibrate total service demand	CARB EMFAC 2011
Vintage_Cost_TRA_BU	Vintage Cost:TRA BU	$/Bus	Per-unit technology costs	Department of Transportation Fuel Cell Bus Life Cycle Model: Base Case and Future Scenario Analysis: http://www.rita.dot.gov/sites/default/files/publications/fuel_cell_bus_life_cycle_cost_model/excel/appendix_a.xls

Variable	Title	Units	Description	Reference
Vintage_Cost_TRA_HD	Vintage Cost:TRA HD	$/Vehicle	Per-unit technology costs	Assessment of Fuel Economy Technologies for Medium- and Heavy-Duty Vehicles: http://www.nap.edu/catalog.php?record_id=12845
Vintage_Cost_TRA_LD	Vintage Cost:TRA LD	$/Vehicle	Per-unit technology costs	"Transitions to Alternative Vehicles and Fuels", National Academies Press, 2013
Vintage_Cost_TRA_MD	Vintage Cost:TRA MD	$/Vehicle	Per-unit technology costs	Assessment of Fuel Economy Technologies for Medium- and Heavy-Duty Vehicles: http://www.nap.edu/catalog.php?record_id=12845
Vintage_Eff_TRA_BU	Vintage Eff:TRA BU	Miles/GGE	Technology efficiencies	Department of Transportation Fuel Cell Bus Life Cycle Model: Base Case and Future Scenario Analysis: http://www.rita.dot.gov/sites/default/files/publications/fuel_cell_bus_life_cycle_cost_model/excel/appendix_a.xls
Vintage_Eff_TRA_HD	Vintage Eff:TRA HD	Miles/GGE	Technology efficiencies	Assessment of Fuel Economy Technologies for Medium- and Heavy-Duty Vehicles: http://www.nap.edu/catalog.php?record_id=12845; 2012 MODEL YEAR ALTERNATIVE FUEL VEHICLE (AFV) GUIDE: http://www.gsa.gov/graphics/fas/2012afvs.pdf
Vintage_Eff_TRA_LD	Vintage Eff:TRA LD	Miles/GGE	Technology efficiencies	"Transitions to Alternative Vehicles and Fuels", National Academies Press, 2013

Variable	Title	Units	Description	Reference
Vintage_Eff_TRA_MD	Vintage Eff:TRA MD	Miles/GGE	Technology efficiencies	Assessment of Fuel Economy Technologies for Medium- and Heavy-Duty Vehicles: http://www.nap.edu/catalog.php?record_id=12845; 2012 MODEL YEAR ALTERNATIVE FUEL VEHICLE (AFV) GUIDE: http://www.gsa.gov/graphics/fas/2012afvs.pdf

2.4.9 VEHICLE CLASS MAPPING BETWEEN EMFAC AND PATHWAYS

Table 19 below shows the mapping of EMFAC to PATHWAYS vehicle classes. LDVs include Light-Duty Autos (LDA), Light-Duty Trucks (LDT), and Motorcycles (MCY).

Table 19: Vehicle class mapping between EMFAC and PATHWAYS

EMFAC2011 Veh & Tech	PATHWAYS Vehicle Class
LDA - DSL	LDA
LDA - GAS	LDA
LDT1 - DSL	LDT
LDT1 - GAS	LDT
LDT2 - DSL	LDT
LDT2 - GAS	LDT
LHD1 - DSL	MDV
LHD1 - GAS	MDV
LHD2 - DSL	MDV
LHD2 - GAS	MDV

EMFAC2011 Veh & Tech	PATHWAYS Vehicle Class
MCY - GAS	MCY
MDV - DSL	LDT
MDV - GAS	LDT
T6 Ag - DSL	MDV
T6 CAIRP heavy - DSL	MDV
T6 CAIRP small - DSL	MDV
T6 instate construction heavy - DSL	MDV
T6 instate construction small - DSL	MDV
T6 instate heavy - DSL	MDV
T6 instate small - DSL	MDV
T6 OOS heavy - DSL	MDV
T6 OOS small - DSL	MDV
T6 Public - DSL	MDV
T6 utility - DSL	MDV
T6TS - GAS	MDV
T7 Ag - DSL	HDV
T7 CAIRP - DSL	HDV
T7 CAIRP construction - DSL	HDV
T7 NNOOS - DSL	HDV
T7 NOOS - DSL	HDV
T7 other port - DSL	HDV
T7 POAK - DSL	HDV
T7 POLA - DSL	HDV
T7 Public - DSL	HDV
T7 Single - DSL	HDV
T7 single construction - DSL	HDV
T7 SWCV - DSL	HDV
T7 tractor - DSL	HDV
T7 tractor construction - DSL	HDV
T7 utility - DSL	HDV
T7IS - GAS	HDV
PTO - DSL	HDV
SBUS - DSL	BUS
SBUS - GAS	BUS

EMFAC2011 Veh & Tech	PATHWAYS Vehicle Class
UBUS - DSL	BUS
UBUS - GAS	BUS
Motor Coach - DSL	BUS
OBUS - GAS	BUS
All Other Buses - DSL	BUS

2.5 Industry & Other

PATHWAYS' Industrial Module (IND) is used to project industrial manufacturing final energy consumption, CO2 emissions, and measure implementation costs for the 26 sectors, 7 End-uses, and 5 fuels listed in Table 20, Table 21, and

Table 22. Energy accounting in the Industrial Module is performed through fuel use projections for each end use in each subsector, with emissions calculated based on the fuels consumed. Note that non-manufacturing industrial activities, like oil and gas exploration, oil refining, agriculture, and TCU each have their own modules and are documented separately.

Table 20. Industrial subsectors

Subsectors	
Apparel & Leather	Mining
Cement	Nonmetallic Mineral
Chemical Manufacturing	Paper
Computer and Electronic	Plastics and Rubber
Construction	Primary Metal
Electrical Equipment & Appliance	Printing
Fabricated Metal	Publishing

Subsectors	
Food & Beverage	Pulp & Paperboard Mills
Food Processing	Semiconductor
Furniture	Textile Mills
Glass	Textile Product Mills
Logging & Wood	Transportation Equipment
Machinery	Miscellaneous

Table 21: Industrial End-Uses

Industrial End-Uses
Conventional Boiler Use
Lighting
HVAC
Machine Drive
Process Heating
Process Cooling & Refrigeration
Other

Table 22. Industrial fuels

Fuels
Electricity
Pipeline Gas
Waste Heat
Diesel
Gasoline

The Industrial Module does not use a detailed stock-rollover mechanism through which users implement measures. Instead, users implement energy efficiency and fuel switching measures that directly lead to percentage changes in the amount and type of energy consumed by specific end uses, spanning all relevant subsectors. Measure penetrations used in scenarios are intended to be exogenously constrained by a high-level understanding of constraints on the depth or speed of deployment.

This section describes methods for calculating final energy consumption (Section 2.5.1), CO_2 emissions (Section 2.5.2), and energy system costs (Section 2.5.3) in the Industrial Module. Section 0 lists data inputs and sources, and Sections 2.5.6 through 2.5.9 take a closer look at major industrial subsectors.

2.5.1 FINAL ENERGY CONSUMPTION

Industrial electricity and natural gas use in PATHWAYS is based on linear extrapolation of the CEC industrial energy use forecasts (2012-2024) made in support of the CALEB 2010 report[14]. CALEB forecasts for these fuels are available for each of the industrial sub-sectors found in PATHWAYS. Industrial diesel consumption in PATHWAYS is based on historical CA industry wide diesel usage from 1992 to 2011. In PATHWAYS, this consumption is split evenly across all subsectors. To complete baseline forecasts, linear regression is used to extend electricity, natural gas, and diesel consumption volumes out to 2050. Emissions inventory records show minimal gasoline usage in manufacturing categories, so baseline gasoline usage is set to zero. Next, subsector fuel use is allocated

[14] http://uc-ciee.org/downloads/CALEB.Can.pdf

across end uses using percentages drawn from the CPUC Navigant Potential Study, 2013[15]. Finally, natural gas and waste heat modifiers from the industrial calculations of the CHP supply module, i.e. waste heat production based on installed CHP capacity and thermal supply parameters in CA according to the DOE and ICF[16], are added to industrial energy use (note: net CHP natural gas use can be negative), split across sub-sectors and end uses proportional to their heating natural gas usage. In the official list of fuels, natural gas is designated as pipeline gas to reflect the possibility that low carbon synthetic and bio-derived gases could be blended with natural gas in the future.

[15] http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M088/K661/88661468.PDF Table 4-3
[16] http://www.eea-inc.com/chpdata/States/CA.html

Equation 60: Reference energy forecast for industrial energy consumption

$$REF_{jefy} = \left((FC.D_{jy} + FC.E_{fy} + FC.NG_{fy}) \times ES_{jef} + CHP_{jefy}\right)$$

New Subscripts

f	fuel type	electricity, pipeline gas, waste heat, diesel, gasoline
y	year	Year of energy use
J	subsector	26 subsectors in Table 20
e	end use	7 end uses in Table 21

New Variables

$FC.D_{jy}$	Forecast of diesel usage for subsector j and year y; fuel type f is implied
$FC.E_{jfy}$	Forecast of electricity usage for subsector j and year y; fuel type f is implied
$FC.NG_{jfy}$	Forecast of natural gas usage for subsector j and year y; fuel type f is implied
ES_{jef}	Energy share breakdown by subsector j, end use e, and fuel type f
CHP_{jefy}	CHP waste heat and fuel use for subsector j, end use e, fuel type f, in year y
REF_{jefy}	Reference industrial energy forecast for subsector j, end use e, fuel type f, in year

2.5.1.1 Energy impacted by measures

Equation 61: Fraction of "impacted fuel" energy altered by measures

$$FIF_{mefy} = max\left(min\left(\frac{y_{sat} - y}{y_{sat} - y_{start}}, 1\right), 0\right) \times SF_{mef}$$

New Variables

FIF_{mefy}	fraction of "impacted fuel" altered per measure m, end use e, and fuel type f in year y
y_{sat}	saturation year
y_{start}	measure start year
SF_{mef}	"stock fraction" altered per measure m, end use e, and fuel type f in the saturation year

Note that the impacted fuel calculation is forced by the *max* and *min* functions to fall within limits of 0 and 1, representing the period prior to implementation and the period after complete saturation, respectively.

2.5.1.2 Energy Efficiency and Fuel Switching

Before the fuel energy change associated with efficiency can be calculated, fuel switching must be accounted for. The fuel energy impacted, FEI, is the energy consumption impacted by a given measure and is subtracted from the impacted fuel type and added to the replacement fuel type. Thus it has no impact when the impacted and replacement fuels are the same.

Equation 62: Fuel energy switched away from impacted fuel

$$FEI_{mefy} = \sum_{j} REF_{jefy} \times FIF_{mefy} \times EF_{mef}$$

New Variables

$\mathbf{FEI_{mefy}}$	impacted fuel energy switched per measure m, end use e, and fuel type f in year y
$\mathbf{EF_{mef}}$	"energy fraction" altered per measure m, end use e, and fuel type f in the saturation year

The "fuel energy replaced" (FER) is the "fuel energy impacted" (FEI) adjusted for any efficiency change described by the measure.

Equation 63: Replaced fuel energy

$$FER_{mefy} = \sum_{i} FEI_{mefy} \times (1 - EEI_{mef})$$

New Variables

FER_{mefy}	replaced fuel energy per measure m, end use e, and replacement fuel f in year y
EEI_{mef}	energy efficiency improvement per measure m, end use e, and replacement fuel f

Equation 64: Final industrial energy

$$I.FEC_{fy} = \sum_{e} \left(\sum_{j} REF_{jefy} + \sum_{m} -FEI_{mefy} + FER_{mefy} \right)$$

New Variables

$I.FEC_{fy}$	industrial final energy consumption of fuel type f in year y

2.5.2 CO_2 EMISSIONS

CO2 emissions from the industrial sector are composed of the final energy demand multiplied by the delivered fuel emissions rates. Emission rates vary over time and are determined in the fuels modules of the model because the content of pipeline gas, delivered electricity, and liquid fuels can be reduced through investments in decarbonizing supply side energy.

Equation 65

$$I.CO2_y = \sum_e I.FEC_{fy} \times CEF_{fy}$$

New Variables

I.CO2$_y$	total industrial CO_2 emissions in year y
CEF$_{fy}$	net CO_2 emission factor for fuel type f in year y

Gross and net CO_2 emissions factors are only different for biomass, where the net CO_2 emission factor is assumed to be zero.

2.5.3 ENERGY SYSTEM COSTS

Energy system costs are defined in PATHWAYS as the incremental capital and energy cost of measures. We apply costs on a levelized ($ per energy) basis to the impacted energy across both energy efficiency and fuel switching.

Equation 66: efficiency and fuel switching costs

$$EEC_y = \sum_m \sum_e \sum_f FEI_{mefy} \times LEC_m$$

New Variables

EEC$_y$	annualized energy efficiency measure costs in year y
LEC$_m$	levelized energy efficiency or fuel switching costs for measure m

2.5.4 MEASURE DEFINITIONS

Table 23 presents representative, but not comprehensive, industrial measures impacting specific end uses across industrial sub-sectors. The lighting measure is an example of the broad efficiency gains possible with LED lighting replacements. The HVAC measures accomplish fuel switching and efficiency goals, with heat pumps reducing total heating energy by (1-(0.75/2.5)) = 70% over Pipeline Gas alternatives and electric resistance heat improving efficiency by (1-(0.75/0.9)) = 16.7%. Both process heat and boilers have pure fuel switching measures impacting 20% and 30% of the total fuel use respectively. Finally, machine drive can be modestly improved (20-30%) by technical improvements, like adjustable speed motors and computer controlled switched reluctance motors.

Table 23: Example efficiency and fuel switching measures for industrial manufacturing

End Use	Measure Name	Stock fract'n	Replacement Fuel	Impacted Fuel	EE Improvement	Start Year	Sat. Year
Lighting	LED Adoption	0.9	Electricity	Electricity	0.75	2013	2050
HVAC	Heat pump	0.675	Electricity	Pipeline Gas	(1-(0.75/2.5))	2020	2050
HVAC	Electric	0.225	Electricity	Pipeline Gas	(1-(0.75/0.9))	2020	2050
Process Heat	Fuel Switch	0.2	Electricity	Pipeline Gas	0	2013	2030
Boiler	Fuel Switch	0.3	Electricity	Pipeline Gas	0	2020	2040
Machine Drv	Adj. Speed	1	Electricity	Electricity	0.2	2013	2050
Machine Drv	Switch'd Reluctance	0.35	Electricity	Electricity	0.3	2013	2050

2.5.5 MODEL DATA INPUTS AND REFERENCES

Table 24 provides details on the key input variables involved in calculating IND reference case fuel use.

Table 24: Industrial manufacturing input variables

Variable	Title	Units	Description	Reference
Data_IND_Ele	Data:IND Ele	GWh	Sectoral electricity demand input data	CEC data used in support of http://uc-ciee.org/downloads/CALEB.Can.pdf
Data_IND_Gas	Data:IND Gas	Mtherms	Sectoral pipeline gas demand input data	CEC data used in support of http://uc-ciee.org/downloads/CALEB.Can.pdf
Data_IND_Oth	Data:IND Oth	Exajoules	Sectoral "other" energy input data	CARB emissions inventory historical data
Energy_Share_IND	Energy Share:IND	%	End-use energy decomposition by subsector	CPUC Navigant Potential Study, 2013.

2.5.6 REFINING

The Refining (REF) module captures energy used in the refining of oil into fuels and other products. Refining Coke, Process Gas, and LPG usage data, spanning 2000 to 2011, come from the CARB GHG Emissions Inventory. Pipeline Gas usage data comes from CEC's 2010 CALEB and spans 2012 to 2024. All of these fuels are allocated to gas utility service territories proportional to refinery electricity demand (broken out by electric service territory). Electricity usage data comes from the CEC's 2009 2010-2020 Energy Demand Forecast, and span 1990 to 2020. Fuels are extrapolated out to 2050 using linear regression and then split across end uses using energy share data from the 2013 CPUC Navigant Potential Study. End uses include Conventional Boiler Use, Lighting, HVAC, Machine Drive, Process Heating, Process Cooling & Refrigeration, and Other. Process heating is the biggest energy end use in refining by an order of magnitude and is met primarily by Process Gas and Pipeline Gas. Waste Heat and Pipeline Gas usage from REF-sited CHP (calculated in the CHP module) are added in to complete the reference case energy usage for REF with Electricity, Pipeline Gas, Coke, Process Gas, LPG, and Waste Heat as fuels.

REF Measures directly reduce energy by an amount based on a stock impact fraction multiplied by end use improvement ratio, ramped in a linear fashion from 0-100% between the measure start and saturation years. With selections for impacted and replacement fuel categories, measure inputs allow fuel switching as well as within-fuel efficiency.

REF Demand Change Measures reduce demand for all refining activity based on a demand change fraction. Year by year reductions are calculated along a linear ramp from zero in 2015 to the year in which the demand change reaches 100% of its potential, typically set to 2050. An important question for the future of REF is whether in-state reductions in oil and gas demand will lead to decreases in in-state refining. The standard assumption for official PATHWAYS scenarios is that refining is proportional to demand and therefore is reduced by demand change measures, but important sensitivities test outcomes when refining is decoupled from in-state demand. Refining emissions are so significant that whether they are proportional to in-state demand or not has a very significant impact on final emissions.

Table 25: Refining input variables

Variable	Title	Units	Description	Reference
Data_REF_Ele	Data:REF Ele	GWh	Sectoral electricity demand input data	Energy Demand 2010-2020, Adopted Forecast, California Energy Commission, December 2009, CEC-200-2009-012-CMF

Variable	Title	Units	Description	Reference
Data_REF_Gas	Data:REF Gas	Mtherms	Sectoral pipeline gas demand input data	CEC data used in support of http://uc-ciee.org/downloads/CALEB.Can.pdf. Allocated to gas utility service territories as a function of refinery electricity demand (broken out by electric service territory). Assumed that LADWP and SCE refining demand met by SCG.
Data_REF_Oth	Data:REF Oth	Exajoules	Sectoral "other" energy input data. Input	CARB GHG Emissions Inventory. Allocated to gas utility service territories as a function of refinery electricity demand (broken out by electric service territory). Assumed that LADWP and SCE refining demand met by SCG.
Energy_Share_REF	Energy Share:REF	%	End-use energy decomposition by subsector	CPUC Navigant Potential Study, 2013.

2.5.7 OIL AND GAS

The Oil and Gas Extraction (OGE) module captures energy used in the extraction of oil and gas, which is dominated by Pipeline Gas. Pipeline Gas inputs are from CEC's 2010 CALEB model[17] and span 2012 to 2024. Electricity inputs are from the CEC's 2009 2010-2020 Energy Demand Forecast, and span 1990 to 2020. Both fuels are extrapolated out to 2050 using linear regression. Waste Heat and Pipeline Gas usage from OGE-sited CHP (calculated in the CHP module) are added in to complete the reference case energy usage for OGE with Electricity, Pipeline Gas, and Waste Heat fuels.

OGE Measures directly reduce energy by an amount based on a stock impact fraction multiplied by end use improvement ratio, ramped in a linear fashion from 0-100% between the measure start and saturation years. With selections for

[17] California Energy Balance Update and Decomposition Analysis for the Industry and Building Sectors http://uc-ciee.org/downloads/CALEB.Can.pdf

impacted and replacement fuel categories, measure inputs allow fuel switching as well as within-fuel efficiency.

OGE Demand Change Measures reduce demand for all oil and gas extraction activity based on a demand change fraction. Year by year reductions are calculated along a linear ramp from zero in 2015 to the year in which the demand change reaches 100% of its potential. An important question for the future of OGE is whether in-state reductions in oil and gas will lead to decreases in in-state extraction.

Table 26: Oil and Gas Extraction input variables

Variable	Title	Units	Description	Reference
Data_OGE_Ele	Data:OGE Ele	GWh	Sectoral electricity demand input data	Energy Demand 2010-2020, Adopted Forecast, California Energy Commission, December 2009, CEC-200-2009-012-CMF
Data_OGE_Gas	Data:OGE Gas	Mtherms	Sectoral pipeline gas demand input data	CEC data used in support of http://uc-ciee.org/downloads/CALEB.Can.pdf

2.5.8 TCU

Transportation Communications and Utilities (TCU) energy supports public infrastructure, like street lighting and waste treatment facilities. Street lighting is so prominent that the TCU sub-categories are "Street lighting" and "TCU Unspecified". Although dominated by Electricity, fuels also include Pipeline Gas, with inputs for both ranging from 1990 to 2024 from the IEPR 2014 Demand Forecast, Mid-Case. These are extrapolated out to 2050 using linear regression. Waste Heat and Pipeline Gas usage from TCU-sited CHP (calculated in the CHP module) are added in to complete the reference case energy usage for TCU with Electricity, Pipeline Gas, and Waste Heat fuels.

TCU measures directly reduce energy by an amount based on a stock impact fraction multiplied by end use improvement ratio, ramped in a linear fashion from 0-100% between the measure start and saturation years. With selections for impacted and replacement fuel categories, measure inputs allow fuel switching as well as within-fuel efficiency. Because TCU energy usage is generally miscellaneous, the most obvious and dominant efficiency measure is the LED conversion of streetlights.

TCU Demand Change Measures reduce demand for street lighting (where they might represent de-lamping) and all other TCU activity based on separate demand change fractions. Year by year reductions are calculated along a linear ramp from zero in 2015 to the year in which the demand change reaches 100% of its potential, typically set to 2050.

Table 27: TCU input variables

Variable	Title	Units	Description	Reference
Data_TCU_Ele	Data:TCU Ele	GWh	Sectoral electricity demand input data	2014 IEPR CEC Consumption Forecast-Mid Demand Case
Data_TCU_Gas	Data:TCU Gas	Mtherms	Sectoral pipeline gas demand input data	2014 IEPR CEC Consumption Forecast-Mid Demand Case

2.5.9 AGRICULTURE

The agricultural module (AGR) tracks the energy use of physical infrastructure of agriculture, like buildings and pumps. Farm vehicles, like tractors, are tracked in the Transportation (TRA) module and livestock, waste, and soil emissions are tracked in the Non-CO_2 module (NON). Agricultural Electricity and Pipeline Gas consumption input data come from the IEPR 2014 Demand Forecast, Mid-Case for years spanning 1990 to 2024. Gasoline usage come from the CARB GHG Emissions Inventory for years 2000-2011 and Diesel usage comes from EIA data on Adjusted Sales of Distillate Fuel Oil by End Use for years 1984-2011. All fuels are extrapolated out to 2050 using linear regression. Waste Heat and Pipeline Gas usage from AGR-sited CHP (calculated in the CHP module) are added in, proportional to Pipeline Gas usage, to complete the reference case energy usage for AGR with Electricity, Pipeline Gas, Diesel, Gasoline, and Waste Heat fuels. These fuels are allocated across end uses HVAC, Lighting, Motors, Refrigeration, Water Heating and Cooling, Process, and Miscellaneous according the percentage breakdowns in the CPUC Navigant Potential Study from 2013[18]. The Miscellaneous category is essentially diesel used for pumping and is the largest energy use category.

AGR measures apply to individual end uses and directly reduce energy by an amount based on a stock impact fraction multiplied by an end use improvement ratio, ramped in a linear fashion from 0-100% between the measure start and saturation years. With selections for impacted and replacement fuel categories, measure inputs allow fuel switching as well as within-fuel efficiency.

[18] http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M088/K661/88661468.PDF

AGR Demand Change Measures reduce demand for all agricultural activity based on a final demand change fractions. Year by year reductions are calculated along a linear ramp from zero in 2015 to the year, typically set to 2050, in which the demand change reaches its final potential.

Table 28: Agricultural input variables

Variables	Title	Units	Description	Reference
Data_AGR_Ele	Data:AGR Ele	GWh	Sectoral electricity demand input data	2014 IEPR CEC Consumption Forecast-Mid Demand Case
Data_AGR_Gas	Data:AGR Gas	Mtherms	Sectoral pipeline gas demand input data	2014 IEPR CEC Consumption Forecast-Mid Demand Case
Data_AGR_Oth	Data:AGR Oth	Exajoules	Sectoral "other" energy input data.	Diesel: EIA Adjusted Sales of Distillate Fuel Oil by End Use Gasoline: CARB GHG Emissions Inventory
Energy_Share_AGR	Energy Share:AGR	%	End-use energy decomposition by subsector	CPUC Navigant Potential Study, 2013.

2.6 Water-Related Energy Demand

PATHWAYS' Water-Energy Module (Water Module) aims to capture the energy demand associated with the procurement, treatment, conveyance and wastewater-treatment of water in the state of California. While a small portion of the overall energy demand in California, (less than .1% of total energy demand or 75.83 GWh in 2011 by our methodology), water-related energy is included in the model in an effort to capture the entirety of the state's energy needs.

The forecasting of this energy demand begins with a forecast of the state's water demand, which comes from the California Water Plan.[19] The California Water Plan projects water demand for each of California's 10 hydrologic regions by demand sector (agriculture, industry, commercial and residential) from 2010 until 2050. For reference, we provide the 10 hydrologic regions and their respective water demand allocations in 2010 in Figure 9.

[19] State of California, Natural Resources Agency, Department of Water Resources. "The Strategic Plan." California Water Plan: Update 2013 1 (2013): 26 Feb. 2015. <http://www.waterplan.water.ca.gov/docs/cwpu2013/Final/0a-Vol1-full2.pdf>.

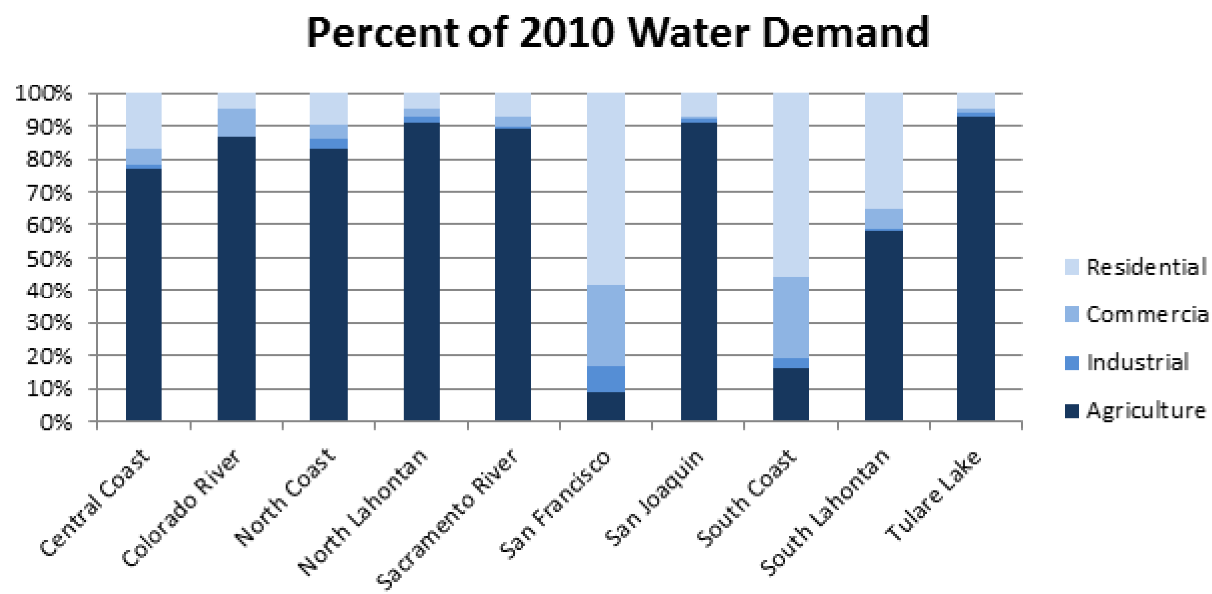


Figure 9. Ten California Hydrologic Regions

With yearly projections of water demand, PATHWAYS allows the user to define incremental water supply portfolios and calculates the electricity demand associated with meeting the state's water demand in each year given the energy intensity of supply, conveyance, and treatment. The energy intensity and supply portfolio options are described further in the following sections.

For industrial, commercial and residential demand, energy demand is broken into four components: supply, treatment, conveyance and wastewater treatment. As the energy intensities of treatment, conveyance and wastewater components do not vary significantly by sector, they are applied uniformly to the 3 sectors as follows:

Table 29. Energy Intensity of Water Supply by Component

Component	Energy Intensity (kWh/Acre-Foot)
Treatment	100
Conveyance	300
Wastewater Treatment	100[20]

For the supply component, we note that energy intensity varies significantly depending on the method of supply. Thus, this component is indexed by supply method. Four supply proxies were chosen as the predominant means of meeting water demand over the projected period of time: desalination, reclaiming (recycling) water, conservation and pumping groundwater. Their respective energy intensities are shown below.

Table 30. Energy Intensity of Water Supply Options

Supply Proxy	Energy Intensity (kWh/Acre-Foot)
Desalination	2500
Reclaimed Water	1000
Conservation	0
Groundwater	600

[20] This value will be adjusted to 500 kWh/Acre-Foot in future versions of the model in an attempt to further improve the model's accuracy.

2.6.1 REFERENCE WATER-RELATED ENERGY DEMAND FORECAST

The State Water Plan features several different projection scenarios for water demand, with variation associated with population growth as well as changes in urban and agricultural density. To be conservative, the Water Module utilizes the water demand projections of the Current Trend Population-Current Trend Density scenario (CTP-CTD), which, as the name implies, sustains today's trends through 2050. Some figures are included below for comparative reference between this scenario and others:

Table 31. State Water Plan Scenarios and Indicators

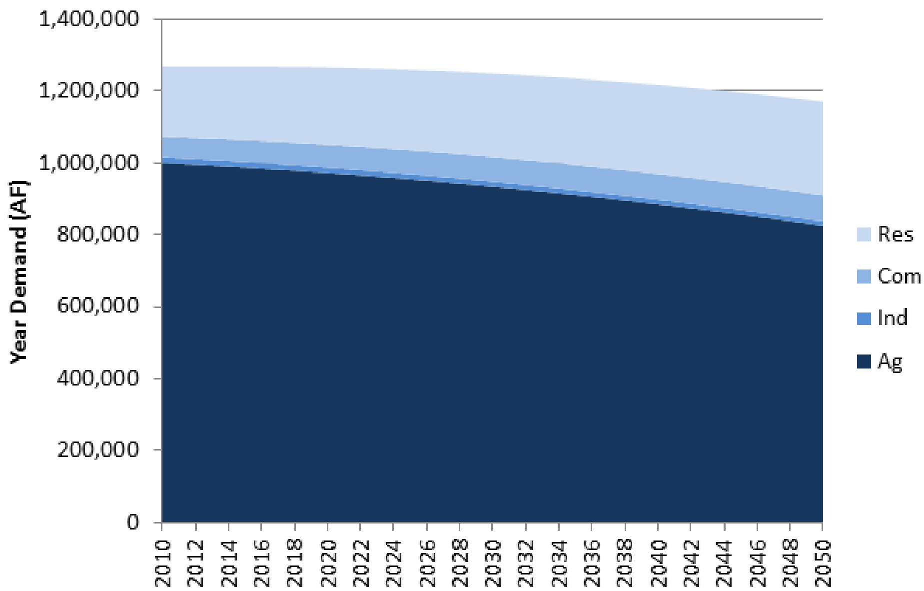
Scenario[21]	2050 Population (millions)	2050 Urban Footprint (million acres)	2050 Irrigated Crop Area (million acres)[3]
CTP-CTD	51.0	6.7	8.9
High Population	69.4	7.6	8.6
Low Population	43.9	6.2	9.0
High Density	51.0	6.3	9.0
Low Density	51.0	7.1	8.7

The CTP-CTD scenario then uses its assumption about population growth and development to project yearly demand in each demand sector in each hydrologic region. Based on historical data, these projections show a lot of fluctuation (for example, years 2023 and 2024 correspond to the droughts of 1976 and 1977). Given the breadth of scope of the California PATHWAYS project and the smaller role that the Water Module plays in it, the year-to-year detail of these projections

[21] Unless explicitly stated, assume current trends for population and density are used; e.g. High Population uses higher than current population trends and current density trends.

was replaced with a smoothed quadratic regression, resulting in the following projection of demand by sector from 2010 to 2050.

Figure 10: Yearly demand (AF) by demand sector, 2010-2050



Note that this projection shows a decrease over time in water demand for agriculture-related use. This is a characteristic of the California Water Plan, which anticipates a decrease in irrigated crop area (as has been observed over the last 10 years) and, thus, a reduction in demand for agricultural water.

2.6.2 WATER SOURCE ENERGY INTENSITIES

The various energy intensities used in the Water Module come from 2 different sources and represent our best attempt at generalizing figures that are highly variable on a case by case basis. For example, the energy intensity of distributing water can vary by a factor of 50, depending on the terrain the water crosses and the method by which it is transmitted. Using the Embedded Energy in Water Studies,[22] the energy intensities for supply (desalination, reclaimed water, groundwater), treatment, conveyance and wastewater treatment are calculated. The GEI study provides summary data on the variation in energy intensity observed across the state of California. Given the bounds on these figures, we chose mid-range energy intensities for each component of energy demand. For industrial, commercial and residential demand, energy demand is broken into four components: supply, treatment, conveyance and wastewater treatment. As the energy intensities of treatment, conveyance and wastewater components do not vary significantly by sector, they are applied uniformly across the non-agricultural sectors as follows (see Table 32). Energy intensities vary significantly depending on the method of supply, so four supply proxies were chosen as the predominant means of meeting water demand over the projected period of time: desalination, reclaiming (recycling) water, conservation and pumping groundwater. Their respective energy intensities are listed in Table NUM.

[22] GEI Consultants, and Navigant Consulting. Embedded Energy in Water Studies Study 2: Water Agency and Function Component Study and Embedded Energy- Water Load Profiles. California Public Utilities Commission Energy Division, 5 Aug. 2011. Web. 26 Feb. 2015. <ftp://ftp.cpuc.ca.gov/gopher-data/energy%20efficiency/Water%20Studies%202/Study%202%20-%20FINAL.pdf>.

Table 32. Energy intensities by component for non-agricultural water demands in PATHWAYS

Component		Observed Lower Bound (kWh/AF)	Observed Upper Bound (kWh/AF)	Mid-range Intensity (kWh/AF)
Supply	Desalination	2,281	4,497	**2,500**
	Reclaimed Water	349	1,111	**1,000**
	Groundwater	295	953	**600**
Treatment		14	234	**100**
Conveyance		15	837	**300**
Wastewater Treatment		1	1,476	**100**

Because agriculture has unique needs pertaining to water compared to the other three sectors (such as lower standards for treatment and no wastewater), energy intensity was not broken into these components but rather one energy intensity factor was applied to the entire water demand associated with the sector. This figure (500 kWh/AF) was informed by the User Manual for the Pacific Institute Water to Air Models[23], who used the same figure to represent the energy intensity of supply and conveyance for agriculture-related water demand.

[23] Wolff, Gary, Sanjay Gaur, and Maggie Winslow. User Manual for the Pacific Institute Water to Air Models. Rep. no. 1. Pacific Institute for Studies in Development, Environment, and Security, Oct. 2004. Web. 26 Feb. 2015. <http://pacinst.org/wp-content/uploads/sites/21/2013/02/water_to_air_manual3.pdf>.

2.6.3 WATER SUPPLY PORTFOLIOS

PATHWAYS relies on historical data to characterize the energy intensity associated with water demand in 2010 and allows the user to specify portfolio compositions for meeting incremental water demands by sector from 2010 to 2050. Note that Conservation is treated as a zero-energy intensity supply source, rather than a demand modifier, so the water demand in PATHWAYS will not account for reductions related to conservation not already included in the California Water Plan. Supply portfolios are interpolated between user-defined portfolios at specific years. The portfolio options are listed below. "Today's Portfolio" is the default supply portfolio in the model, aimed to represent the likely breakdown of supply across each sector. The particular figures in this portfolio are based on 10% conservation, a halfway point towards the goal of 20% reduction by 2020. As urban water management plans and integrated water resource management plans emphasize local supply, we assume that the remaining supplies are mostly local groundwater or new reclaimed water.

Table 33. "Today's portfolio": Current water portfolio by sector

Supply Proxy	Agriculture	Industrial	Commercial	Residential
Desalination	0%	0%	0%	0%
Reclaimed Water	0%	40%	40%	40%
Conservation	0%	10%	10%	10%
Groundwater	100%	50%	50%	50%

Table 34. “High Groundwater & Reclaimed” Portfolio

Supply Proxy	Agriculture	Industrial	Commercial	Residential
Desalination	0%	10%	10%	10%
Reclaimed Water	0%	40%	40%	40%
Conservation	0%	10%	10%	10%
Groundwater	100%	40%	40%	40%

Table 35. “High Reclaimed” Portfolio

Supply Proxy	Agriculture	Industrial	Commercial	Residential
Desalination	0%	20%	20%	20%
Reclaimed Water	0%	40%	40%	40%
Conservation	0%	20%	20%	20%
Groundwater	100%	20%	20%	20%

Table 36. Mixed, Low Groundwater” Portfolio

Supply Proxy	Agriculture	Industrial	Commercial	Residential
Desalination	0%	25%	25%	25%
Reclaimed Water	0%	40%	40%	40%
Conservation	0%	25%	25%	25%
Groundwater	100%	10%	10%	10%

Table 37. Mixed, No Groundwater

Supply Proxy	Agriculture	Industrial	Commercial	Residential
Desalination	0%	25%	25%	25%
Reclaimed Water	0%	45%	45%	45%

Conservation	0%	30%	30%	30%
Groundwater	100%	0%	0%	0%

Table 38. Mixed, Low Conservation

Supply Proxy	Agriculture	Industrial	Commercial	Residential
Desalination	0%	0%	25%	25%
Reclaimed Water	0%	0%	55%	55%
Conservation	0%	0%	10%	10%
Groundwater	100%	100%	10%	10%

2.6.4 WATER-RELATED MEASURES

Some measures defined in the energy sectors in PATHWAYS have implications for water demand – for example, urban water efficiency programs can be implemented as demand change measures in the Commercial and Residential sectors under water heating measures. These reduce both water demand and energy demand. The Water Module in PATHWAYS does not interact dynamically with these types of demand change measures, so the user must specify parallel measures in the Water Module to reflect water demand-related impacts. This can be achieved through the supply portfolio composition, specifically by increasing the contribution of Conservation as a water supply source.

2.6.5 INTEGRATION OF WATER-RELATED LOADS IN PATHWAYS

Water-related loads are incorporated into the electricity module using two different approaches. Desalination loads, which may be used in the electricity module to help balance renewables, are allocated into weekly electricity demand based on seasonal trends in the demand for water in the sectors that are supplied by desalination (commercial, industrial, and residential in the scenarios investigated in PATHWAYS). Industrial water demand is assumed to be flat over the course of the year. For residential and commercial demand, the Metropolitan Water District of Southern California's data on monthly water sales for all member agencies for 2012 were used as representative distributions of water demand over the 12 months of the year. The resulting weekly desalination loads are then included in the electricity sector as flexible loads with a user-defined load factor and modeled using the same approach applied to grid electrolysis and power-to-gas. The default load factor for desalination plants is 79%, which allows the resource to follow the seasonal variation in demand, but not provide significant flexibility to the grid.

All other electricity demands related to water (non-desalination supply, treatment, conveyance, and wastewater treatment) are included in the TCU sector (transportation, communications, and utilities) annual electricity demand and are shaped throughout the year using the load shaping module described in the Electricity Sector documentation.

3 Energy Supply

The final energy demand projections described above are used to project energy supply stocks and final delivered energy prices and emissions. This makes the PATHWAYS supply and demand dynamic and allows PATHWAYS to determine inflection points for emissions reductions and costs for each final energy type (i.e. electricity, pipeline gas, etc.) as well as opportunities for emissions reduction using a variety of different decarbonization strategies. PATHWAYS models twelve distinct final energy types listed in Table 39 that can be broadly categorized as electricity, pipeline gas, liquid fuels, and other. For each final energy type, PATHWAYS models different primary energy sources and conversion processes. Additionally, PATHWAYS models delivery costs for some final energy types. The methodology for calculating the costs and emissions of these supply choices is described in this section.

Table 39. Final energy types

Energy Type	Energy Type Category
Electricity	Electricity
Pipeline Gas	Pipeline Gas
Liquefied Pipeline Gas (LNG)	
Compressed Pipeline Gas (CNG)	
Gasoline	Liquid Fuels
Diesel	
Kerosene-Jet Fuel	
Hydrogen	
Refinery and Process Gas	Other
Coke	
LPG	
Waste Heat	

3.1 Electricity

The electricity module simulates the planning, operations, cost, and emissions of electricity generation throughout the state of California. This module interacts with each of the energy demand modules so that the electricity system responds in each year to the electricity demands calculated for each subsector. Both planning and operations of the electricity system rely not only on the total electric energy demand, but also on the peak power demand experienced by the system, so the module includes functionality to approximate the load shape from the annual electric energy demand. Interactions between the load shaping, generation planning, system operations, and revenue requirement modules are summarized in Figure 11. The subsector energy demand calculated within each sector demand module first feeds into a Load Shaping module to build an hourly load shape for each year in the simulation. This load shape drives procurement to meet both an RPS constraint and a generation capacity reliability constraint in the Planning Module. System operations are then modeled based on the resources that are procured in the Planning Module and the annual load shapes, and finally the results of the operational simulation and the capital expenditures from the Planning Module are fed into simplified revenue requirement and cost allocation calculations. The outputs of the Electricity Module include: generation by resource type and fuel type, electricity sector emissions, statewide average electricity rates, and average electricity rates by sector. Each sub-module is described in this section.

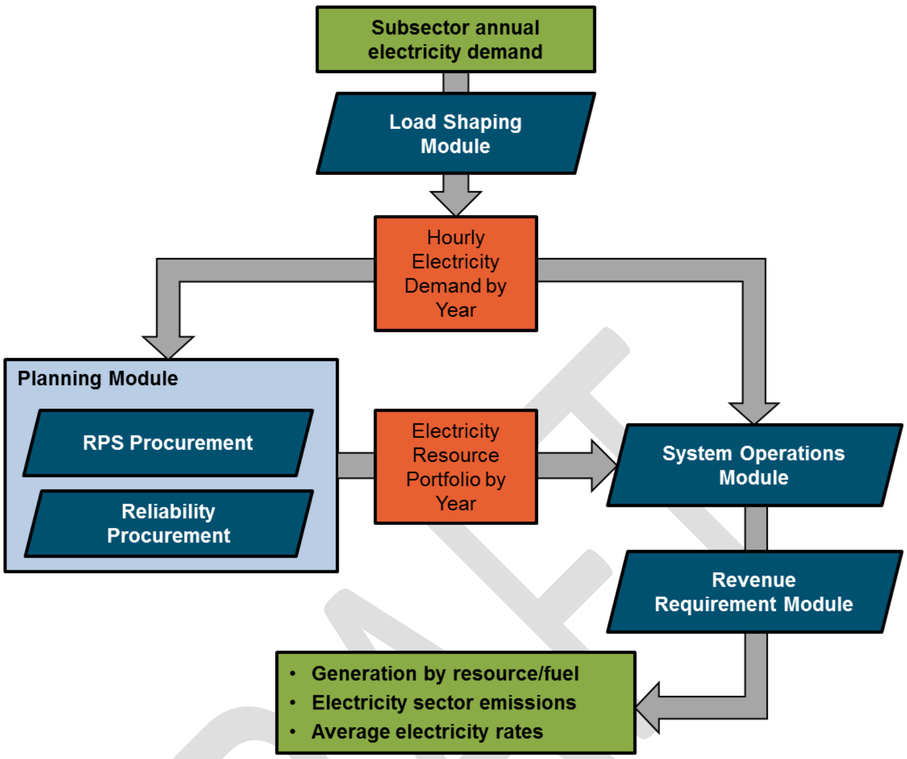


Figure 11. Summary of electricity module

3.1.1 LOAD SHAPING

Single year hourly load shapes were derived for 18 sectors/subsectors based on available hourly load and weather data. For each subsector, shapes were obtained from publicly available data sources, including DEER 2008, DEER 2011, CEUS, BeOpt, and PG&E Static and Dynamic load shapes. For each temperature-sensitive subsector, corresponding temperature data was obtained from each of the 16 climate zones.

3.1.1.1 Load Shaping Methodology

The load shaping module first requires normalization of each input load shape from its corresponding weather year to the simulation year. This process occurs in two steps. First, the load shape is approximated as a linear combination of the hourly temperature in each climate zone, the hourly temperature in each climate zone squared, and a constant. This regression is performed separately for weekdays and weekends/holidays to differentiate between behavioral modes on these days.

Equation 67.

$$\boldsymbol{x_i} \approx \sum_{k\in CZ}\left[\boldsymbol{a_{ik}w_{ik}^2} + \boldsymbol{b_{ik}w_{ik}}\right] + \boldsymbol{c_{ik}}$$

where x_i is the input load shape, w_{ik} is the hourly temperature in climate zone k in the weather year associated with the input load shape, and a_{ik}, b_{ik}, and c_{ik} are constants. Next, the hourly temperature data for the simulation year in PATHWAYS is used to transform the input load shapes into the same weather year. This process also occurs separately for weekdays and weekends/holidays.

Equation 68.

$$\boldsymbol{y_i} \approx \sum_{k\in CZ}\left[\boldsymbol{a_{ik}W_k^2} + \boldsymbol{b_{ik}W_k}\right] + \boldsymbol{c_{ik}}$$

where W_k is the hourly temperature in climate zone k in the PATHWAYS simulation weather year. Each set of weekday and weekend/holiday shapes are then combined into a single yearlong hourly shape to match the weekend/holiday schedule of the PATHWAYS simulation year. This results in 61 load shapes that reflect the same weather conditions and weekend/holiday schedules as the PATHWAYS simulation year.

The next step is to combine the load shapes to best reflect both the total historical hourly load and the annual electricity demand by subsector. The model achieves this by normalizing each load shape so that it sums to 1 over the year and selecting scaling factors that represent the annual electricity demand associated with each shape. These scaling factors are selected to ensure that the total electricity demand associated with the load shapes in each subsector sums to the electricity demand in that subsector in a selected historical year. An optimization routine is also used to minimize the deviation between the sum of the energy-weighted hourly load shapes and the actual hourly demand in the same historical year, based on data from the CAISO's OASIS database.

The optimization routine includes two additional sets of variables to allow for more accurate calibration to the historical year. The first set of variables addresses limitations in the availability of aggregate load shapes by subsector. Because some of the load shapes being used represent a single household or a single building, aggregation of these shapes may result in more variable load shapes than are seen at the system level. To account for this, the model shifts each load shape by one hour in each direction and includes these shifted load shapes in the optimization in addition to the original load shape. The model then selects scaling factors for each of the three versions of each shape to automatically smooth the shapes if this improves the fit to hourly historical data.

In addition to the load shape smoothing variables, a set of constants are also included in the model for each subsector. This allows the model to translate load shapes up and down (in addition to the scaling) to best approximate the hourly historical load. The scaling factors and constants solved for in the optimization routine are then used to construct a single shape for each subsector. These shapes are input into PATHWAYS and are scaled in each year according to the subsector electricity demand to form the system-wide hourly load shape. Example load shapes derived using this process are shown in Figure 12. At left, the average daily load shape for weekdays in September corresponding to historical 2010 demand is shown. For illustration, the load shape at right reflects the impacts of reducing all lighting demands by 50% from the 2010 historical demand.

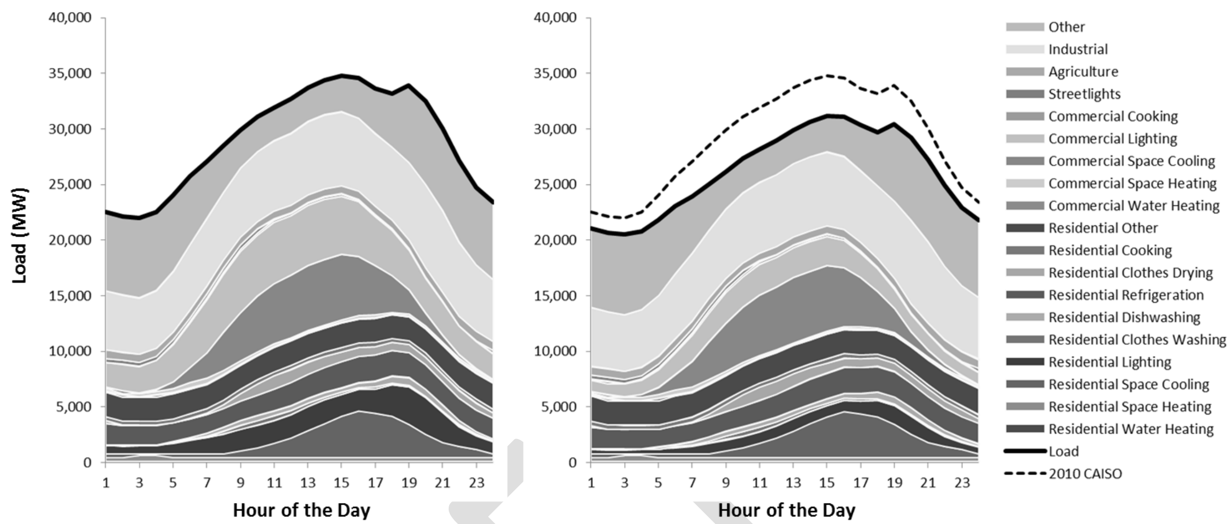


Figure 12. Example load shaping: impact of 50% reduction in lighting demand in average California load shape for weekdays in September, 2010.

Some subsectors in PATHWAYS do not have available representative load shapes. The load shaping module combines these subsectors into an "undefined" subsector and models their contribution to the demand in the optimization routine as a linear combination of all of the available load shapes and a constant. After the optimization routine has solved, the difference between the historical hourly demand and the aggregated hourly shape of all defined subsectors is normalized to sum to 1 and this shape is used to represent any subsectors in PATHWAYS that lack specific load shape information.

3.1.2 GENERATION PLANNING

The aggregate load shape is used to inform generation planning, which occurs in three stages: user-specified resources, renewable policy compliance, and reliability requirement compliance. These are described below.

1. **Specified Resources.** For systems in which resource plans are available, the user may specify the capacity (in MW) of, or annual energy (in GWh) from, each generating resource in each year in the “Time-Dependent Generator Attributes” table. Vintages must also be supplied for this fleet of *specified resources* so that they can be retired at the end of their useful life. Early retirement can be imposed by reducing the total installed capacity of a resource type in future years. The model will retire resources according to age (oldest retired first) to meet the yearly capacities specified by the user. In addition, the model will replace generators at the end of their useful life with new resources (with updated cost and performance parameters) of the same type to maintain the user specified capacity in each year. If the resource capacities are not known after a specific year then the user can specify the capacity to be “NaN” and the model will retire resources without replacement at the end of their useful lifetimes.

2. **Renewable Energy Compliance.** In the second stage of generation planning, the model simulates renewable resource procurement to meet a user-specified renewable portfolio standard (RPS). In each year, the renewable net short is calculated as the difference between the RPS times the total retail sales and the total sum of the renewable generation available from specified resources and resources built in prior years. This renewable net short is then supplied with additional renewable build according to user-defined settings. The user can define resource composition rules in each year or a subset of years (eg. If the user specifies 50% wind and 50% solar in 2030 and 80% solar and 20% wind in 2050, the model will fill the net short in 2030 with 50% wind and

50% solar and will linearly interpolate between this composition and 80% solar, 20% wind by 2050 for filling the net short in all years between 2030 and 2050).

Once the renewable build and composition is determined for each year, PATHWAYS selects resources from the same database that is used by the RPS Calculator to meet the specified procurement strategies in a least-cost way. For example, if the model calls for 1,000 GWh of solar resources to be procured in a given year, PATHWAYS will select solar resources on a least-cost basis to meet the energy target of 1,000 GWh/yr. The costs of these resources then feed into the renewable generation fixed cost component of the revenue requirement calculation. The database also includes transmission costs for each project, which feed into the transmission fixed cost component of the revenue requirement calculation.

3. **Reliability procurement.** The final stage in generation planning is to ensure adequate reliable generating capacity to meet demand. In each year, the model performs a load-resource analysis to compare the reliable capacity to the peak electricity demand. The reliable capacity of the renewable resources is approximated by the total renewable generation level in the hour with the highest net load in the year, where the net load equals the total load minus the renewable generation. The reliable capacity of dispatchable resources is equal to the installed capacity. When the total reliable capacity does not exceed the peak demand times a user-specified planning reserve margin, the model builds additional dispatchable resources with a user-specified

composition in each year.[24] The default planning reserve margin is equal to 15% of peak demand. The final resource stack determined for each year by the electricity planning module feeds into both the system operations and the revenue requirement calculations. These calculations are described in the following sections.

3.1.3 SYSTEM OPERATIONS

System operations are modeled in PATHWAYS using a loading order of resources with similar types of operational constraints and a set of heuristics designed to approximate these constraints. The system operations loading order is summarized in Figure 13. The model first simulates renewable and must-run generation; then approximates flexible load shapes; dispatches energy-limited resources, like hydropower; dispatches energy storage resources; simulates dispatchable thermal resources with a stack model; and finally calculates any imbalances (unserved energy or renewable curtailment). The outputs of the Operational Module include: generation by resource, annual operating cost, renewable curtailment, and exports of electricity.

[24] While peak demand and renewable ELCC's are approximated in this model for the purposes of approximating contributions to economy-wide cost and carbon emissions, the fidelity of the PATHWAYS model is not adequate to inform quantitative electricity-system planning studies, so these parameters should not be examined for use in more detailed planning or operational studies.

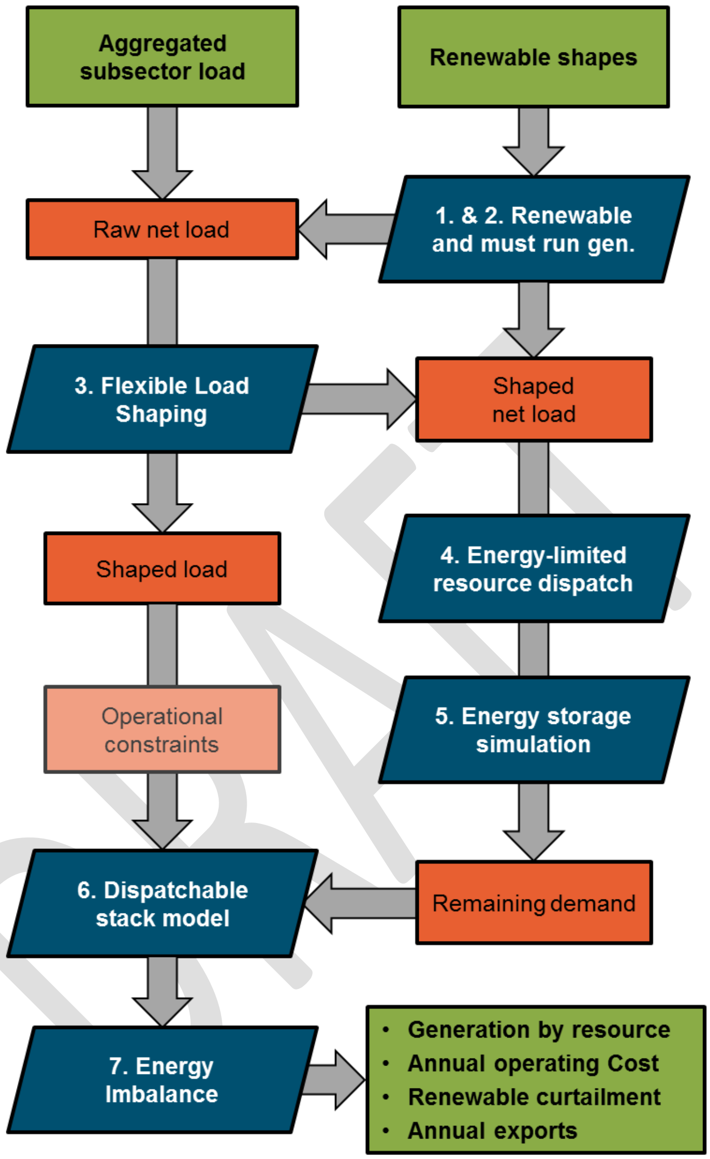


Figure 13. Summary of Electricity System Operations logic

Consistent with this modeling framework, generation resources must each be classified into one of the following operational modes: must-run; variable renewable; energy-limited; and dispatchable. These classifications are listed for the resource types in this analysis in Table 40.

Table 40. Operational modes by resource type

Technology	Operational Mode
Nuclear	Must-run
CHP	Must-run
Coal	Dispatchable
Combined Cycle Gas (CCGT)	Dispatchable
CCGT with CCS	Dispatchable
Steam Turbine	Dispatchable
Combustion Turbine	Dispatchable
Conventional Hydro	Energy-Limited
Geothermal	Must-run
Biomass	Energy-Limited
Biogas	Energy-Limited
Small Hydro	Must-run
Wind	Variable Renewable
Centralized PV	Variable Renewable
Distributed PV	Variable Renewable
CSP	Variable Renewable
CSP with Storage	Variable Renewable

3.1.3.1 Must run resources

Must run resources are modeled with constant output equal to their installed capacity times their availability after considering outages in each year or with constant output that sums to the input annual energy, depending on user specifications. These resources run regardless of the conditions on the system and are therefore scheduled first.

3.1.3.2 *Variable renewable resources*

Variable renewable resources include any resource that has energy availability that changes over time and has no upward dispatchability. This includes all wind and solar resources. For each of these resources, a resource shape is selected, which characterizes the maximum available power output in each hour. These shapes are scaled in each year to match the total annual energy generation determined by the renewable procurement calculation. These resources can either be constrained to never generate in excess of these scaled renewable shapes (curtailable) or constrained to generate at levels that always exactly match the scaled renewable shapes (non-curtailable). The curtailment is affected by both the load and the ability of other resources on the system to balance the renewable resources. Renewable curtailment is therefore approximated as a *system imbalance* after all other resources have been modeled. The curtailability assumptions for variable renewable resources are summarized in Table 41.

Table 41. Operating assumptions for renewable resources

Technology	Able to Curtail?
Geothermal	No
Biomass	No
Biogas	No
Small Hydro	No
Wind	Yes

Technology	Able to Curtail?
Centralized PV	Yes
Distributed PV	No
CSP	Yes
CSP with Storage	No[25]

3.1.3.3 Flexible Loads

Flexible loads are modeled at the subsector level. For each demand subsector, the user specifies what fraction of the load is flexible and the number of hours that the load can be shifted. The model approximates each flexible load shape as the weighted sum of a 100% rigid load shape component and a 100% flexible load shape component, which in the most extreme case can move in direct opposition to the hourly rigid load shape over the course of each week:

Equation 69.

$$L_t = (1-x)\hat{L}_t + xF_t$$

where $\hat{L}_t$ is the subsector load shape with no flexibility, F_t is a perfectly flexible load shape, and x is a coefficient between 0 and 1. Most flexible loads are not, however, perfectly flexible. When an energy service can only be shifted by a limited amount of time, the portion of the load that acts as perfectly flexible in

[25] CSP with Storage resources must generate according to the hourly shape in each hour, but the hourly shape utilizes the energy storage module logic to approximate the dispatchability of these resources.

Equation 29 must account for this limitation. In PATHWAYS, this is accomplished with the following approximation. For each subsector, the load shape is shifted over various time durations. For each shift duration, the resulting load shape is approximated by a linear combination of the original load shape and an inverted load shape (the average load minus the original load shape):

Equation 70

$$\hat{L}_{t-s} \approx a\hat{L}_t + b\left[\bar{L} - \hat{L}_t\right]$$

where s is the time shift and $\bar{L}$ is the average of $\hat{L}_t$ over the time scale of interest (one week for most loads, but one year for loads that can provide seasonal flexibility). The coefficients a and b can be found for each subsector as functions of s using least squares fits to the load shape data. In PATHWAYS, a load that can shift by s hours provides $\frac{b(s)}{a(s)+b(s)}$ of load that can act in complete opposition to the original load shape. This portion of the partially flexible load is therefore conservatively modeled as completely flexible. PATHWAYS stores $\frac{b(s)}{a(s)+b(s)}$ for each subsector and various values of s and uses these functions to approximate x in Equation 69:

Equation 71.

$$x = f \times \frac{b(s)}{a(s) + b(s)}$$

where f is the portion of the subsector load that can be shifted s hours. Both f and s are inputs that must be provided by the user for each subsector in each case. The flexible portion of the load in the model is dynamically shaped to flatten the net load (load net of must-run resources and variable renewables) on a weekly basis or on an annual basis in each year. The flexible load dispatch therefore changes both with demand measures and renewable supply measures.

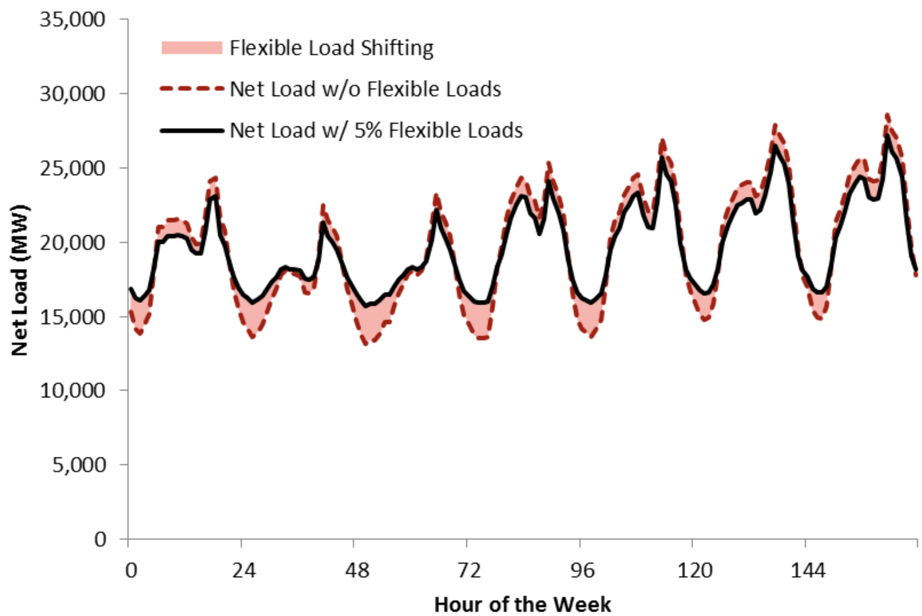


Figure 14. Example of flexible load shifting – 5% of the gross load assumed to be 100% flexible within the week.

The effects of introducing flexible loads on the total net load is shown in Figure 14 for an example week in which 5% of the gross load is approximated as 100% flexible within the week.

In addition to subsector-level flexible loads, flexible fuel production (electrolysis to produce hydrogen, power to gas, compression of pipeline gas, and liquification of pipeline gas) and desalination is modeled in PATHWAYS. These loads are modeled as *negative* energy-limited resources (described in section 1.1.3.5), with seasonal energy constraints. Produced fuels (hydrogen, compressed pipeline gas, and liquid pipeline gas) are assumed to be storable over several weeks so seasonal allocation of energy demand to produce these fuels is driven by seasonal imbalances between the load and the availability of renewables. Seasonal demand for desalination is instead driven by seasonal non-agricultural water demands, which are calculated in the Water Module. The flexibility is also limited by the extent to which the facilities have been oversized to accommodate low load factors. The user inputs the assumed load factor for each fuel production load and for desalination plants to tune the amount of flexibility provided by the new loads. The default load factors are listed in Table 42.

Table 42. Default load factors for potentially flexible desalination and fuel production loads

Load	Default Load Factor
Desalination	0.79
Grid Electrolysis	0.25
Power to Gas	0.25
Compressed Natural Gas	1.0 (inflexible)
Liquefied Natural Gas	1.0 (inflexible)

3.1.3.4 Electric Vehicle Charging

Electric vehicle charging is a special class of flexible loads. Because additional data are available on driving demand patterns, PATHWAYS is able to constrain flexible electric vehicle charging more strictly according to behavior and ability to dispatch load. In order to design these constraints, data on vehicle trips from the 2009 National Household Travel Survey were used to simulate the driving and charging patterns of a fleet of 10,000 electric vehicles (this fleet size was determined to be adequately large to capture appropriate levels of charging shape diversity for an hourly resolution simulation), each with a 30 kWh battery and 0.311 kWh/mi efficiency (96.5 mile range). Vehicle days were selected regardless of geography or vehicle type, reflecting the modeling philosophy that adoption of new technologies should not necessarily alter the magnitude or quality of delivered energy services to achieve carbon goals. Each vehicle was randomly selected from the database and charging patterns were derived over the course of the day based on two rules:

1. As soon as the vehicle is parked at a location with a charging station, the vehicle charges at a fixed power (3.3kW) until either the battery is full or the car is unplugged in order to make its next trip. Simulations were performed in which chargers were assumed to be available only at home and in which chargers were assumed to be available both at home and at work, providing two distinct charging shapes.

2. The charge state of the battery at midnight at the end of the day is equal to the charge state at midnight at the beginning of the day to

ensure that the charging behavior on the simulated day does not impact the ability of the car to provide the needed services on the next day.

3. If the vehicle does not have enough charge in its battery to complete a trip on the simulated day, it is discarded and flagged as an unlikely candidate for electric vehicle adoption. The percent of vehicle-days found to be ineligible for electric vehicle adoption was found to depend on the availability of workplace chargers and whether the day was a weekday or weekend/holiday. The driving demand could be met for 93% of selected vehicle-weekdays without running out of charge if charging was only available at home, while demand could be met for 95.3% of vehicle-weekdays if workplace charging was also available. Weekend driving demands were more challenging to meet given the assumed vehicle charging parameters. Driving demand could be met for 80.7% of selected vehicle-weekends if charging was only available at home and 86.2% if charging was also available at work.

This simulation provided an “Immediate” charging shape, in which vehicles are charged as soon as possible to prepare for the next trip. In order to bound the flexibility of the EV charging loads, this simulation was repeated by altering the first rule so that vehicles were instead charged immediately before the next trip so as to simulate the maximum potential to delay the charging load (“Just-in-time” charging). The charging rate was also fixed at 6.6kW for this simulation. These simulations provided 8 EV charging shapes:

Table 43. Simulated electric vehicle charging shapes

Shape No.	Day Type	Charger Locations	Charging Strategy
1	Weekday	At-home only	Immediate
2	Weekday	At-home only	Just-in-time
3	Weekday	At-home and workplace	Immediate
4	Weekday	At-home and workplace	Just-in-time
5	Weekend	At-home only	Immediate
6	Weekend	At-home only	Just-in-time
7	Weekend	At-home and workplace	Immediate
8	Weekend	At-home and workplace	Just-in-time

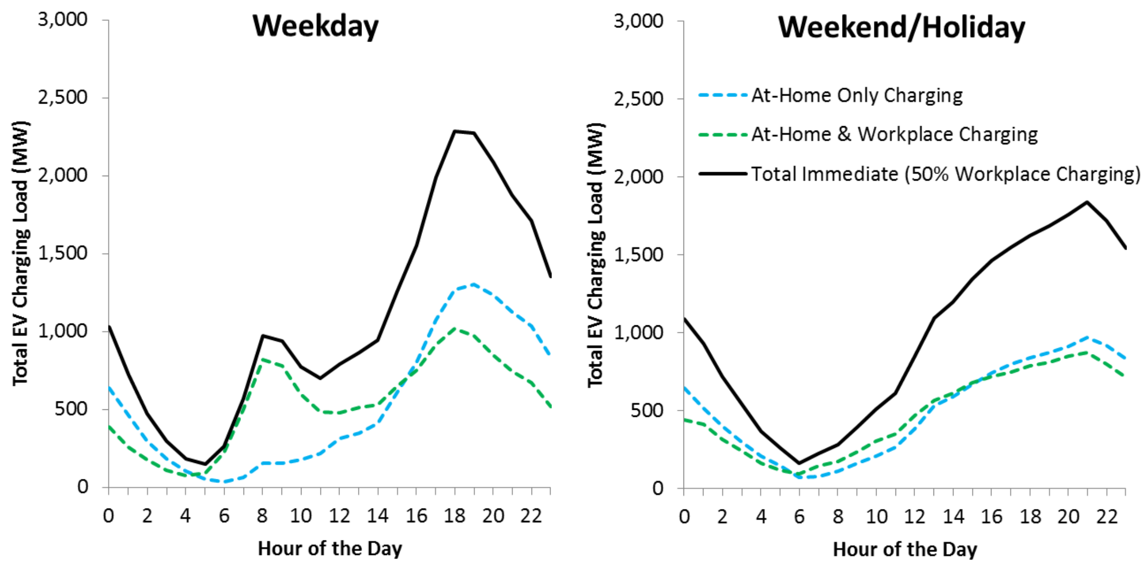


Figure 15. Weekday and Weekend/Holiday EV Charging shapes broken out by charger availability for a case with 50% workplace charger availability

In PATHWAYS, these shapes are combined for each case to build a single annual Immediate charging shape and a single annual Just-in-time charging shape based on the simulation calendar year and the user-defined availability of workplace charging for each case. For example, if 50% of EV drivers are able to charge their vehicle at work, then the Immediate charging shape is equal to 0.5 times the "At-home and Workplace" charging shape plus 0.5 times the "At-home only" charging shape. This example is illustrated in Figure 15.

To simulate electric vehicle charging flexibility, PATHWAYS uses the Immediate and Just-in-time charging shapes to bound the cumulative energy demand for electric vehicle charging in each hour. The Just-in-Time charging shape provides a lower bound for the cumulative charging energy (ie. if the vehicle fleet as a whole is not charged at the level required by the Just-in-Time charging shape, then some vehicles will not be adequately charged in time for their next trip). Similarly, the Immediate charging shape provides an upper bound on the cumulative energy demand for charging (ie. if the cumulative energy delivered to vehicles exceeds that associated with the Immediate charging shape, then the model is attempting to deliver energy to a vehicle that is not yet plugged in). In PATHWAYS these bounds are translated into constraints that make use of the energy storage logic (described in Section 3.1.3.6) to simulate delayed (or stored) electric vehicle charging over time. The portion of the electric vehicle load that is treated in this manner is equal to the portion of the light duty vehicle subsector demand that the user specifies as flexible. The remaining vehicle electricity demand uses the Immediate charging shape derived for the case.

3.1.3.5 Energy-limited resources

Energy-limited resources include any resource that must adhere to a specified energy budget over a weekly time horizon. Some energy-limited resources, like conventional hydropower, have energy budgets that change over time to account for seasonal fluctuations in resource availability and other constraints. Other energy-limited resources, like biomass and biogas, use a dynamic weekly energy budget that distributes resource use between weeks according to the relative electricity imbalance (between load and must-run plus renewable resources) across the weeks. For renewable energy-limited resources, the energy budget ensures that energy from the resources is being delivered for RPS compliance and the energy-limited dispatch also allows the resource to contribute to balancing the system. In addition to the weekly energy budgets, these resources are constrained by weekly minimum and maximum power output levels as well. The dispatch for these resources is approximated using the following heuristic. The method is illustrated in Figure 16 and Figure 17.

1. A normalized hourly demand shape is calculated from the load net of all must-run and variable renewable resources. This net load shape is first translated on a weekly basis so that it averages to zero in each week.

Equation 72

$$n_t = \hat{n}_t - \bar{n}$$

2. The zero-averaged demand shape is then scaled so that the minimum to maximum demand over the course of each week is equal to the minimum to maximum power output of the energy-limited resource.

Equation 73

$$N_t = (P_{max} - P_{min}) \times n_t$$

3. The scaled demand shape is then translated so that the total weekly demand sums to the energy budget of the energy-limited resource.

Equation 74

$$M_t = N_t + \frac{E}{168\text{hrs/wk}}$$

4. The transformed demand shape calculated in Step 3 will necessarily violate either the minimum or maximum power level constraints for the energy-limited resource in some hours, so two additional steps are required to meet the remaining constraints. In the first of these steps,

the transformed demand shape is forced to equal the binding power constraint in hours when it would otherwise violate the constraint.

Equation 75

$$L_t = \begin{cases} P_{min} & \text{if } M_t < P_{min} \\ M_t & \text{if } P_{min} \leq M_t \leq P_{max} \\ P_{max} & \text{if } M_t > P_{max} \end{cases}$$

5. The *truncation* adjustment in Step 4 impacts the summed weekly energy of the transformed demand shape, so a final step is required to re-impose the energy budget constraint. In the weeks in which the transformed demand shape exceeds the energy budget, the model defines a downward capability signal equal to the difference between the transformed demand shape and the minimum power level. A portion of this signal is then subtracted from the transformed demand shape so that the weekly energy is equal to the energy budget. In the weeks in which the transformed demand shape does not meet the energy budget, the model defines an upward capability signal equal to the difference between the maximum power level and the transformed demand shape. A portion of this signal is then added to the transformed demand shape so that the weekly energy is equal to the energy budget. This energy adjustment is summarized by:

Equation 76

$$P_t = \begin{cases} L_t + (E - \Sigma L_t)\dfrac{L_t - P_{min}}{\sum(L_t - P_{min})} & \text{if } \Sigma L_t \geq E \\ L_t + (E - \Sigma L_t)\dfrac{P_{max} - L_t}{\sum(P_{max} - L_t)} & \text{if } \Sigma L_t < E \end{cases}$$

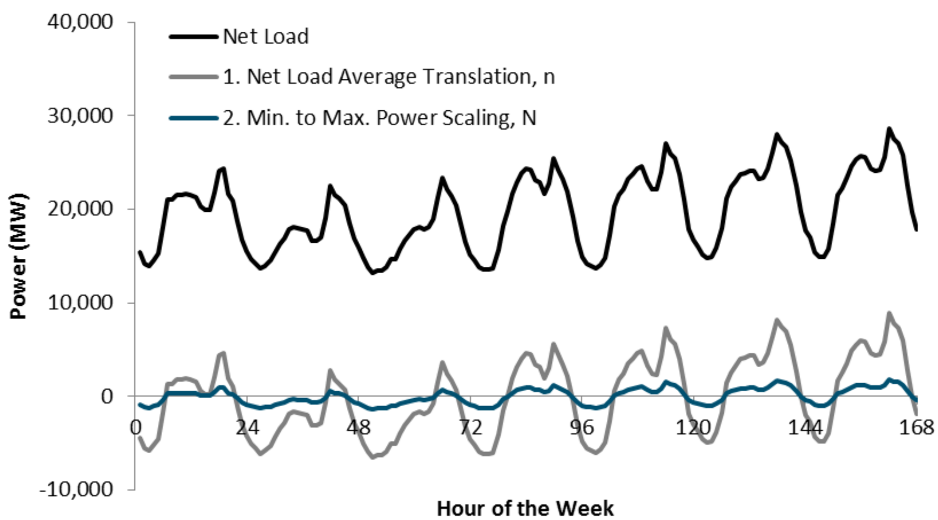


Figure 16. Energy-limited resource dispatch Steps 1 & 2 - Normalization and scaling of the net load shape

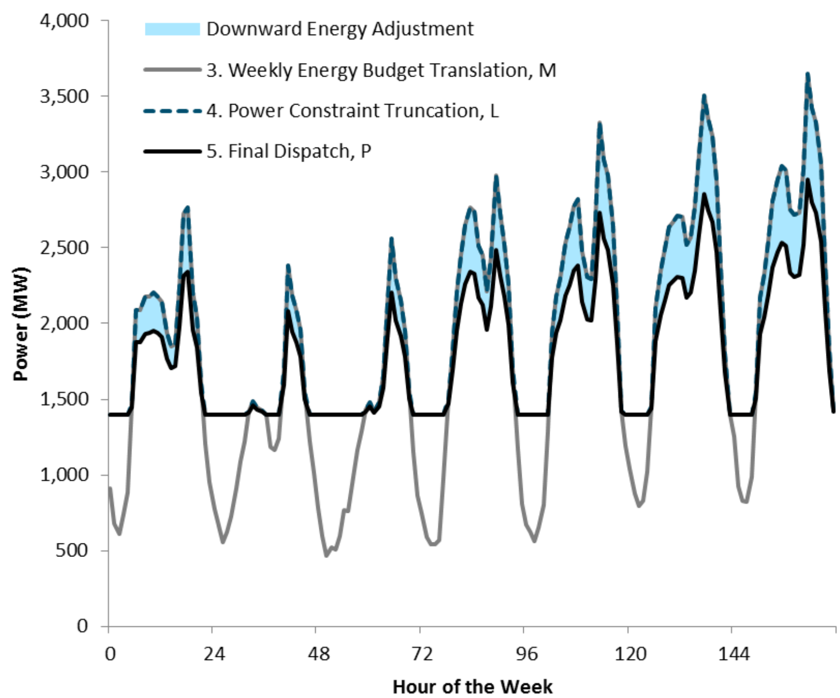


Figure 17. Energy-limited resource dispatch Steps 3 - 5 – Translation, truncation, and energy budget adjustment

3.1.3.6 Energy storage

Energy storage resources in PATHWAYS are aggregated into a single equivalent system-wide energy storage device with a maximum charging capacity, maximum discharging capacity, maximum stored energy capacity, and roundtrip efficiency. The simplified energy storage device is described schematically in Figure 18. The key variables are the charging level, C_t, the discharging level, D_t, and the stored energy, S_t, in each hour.

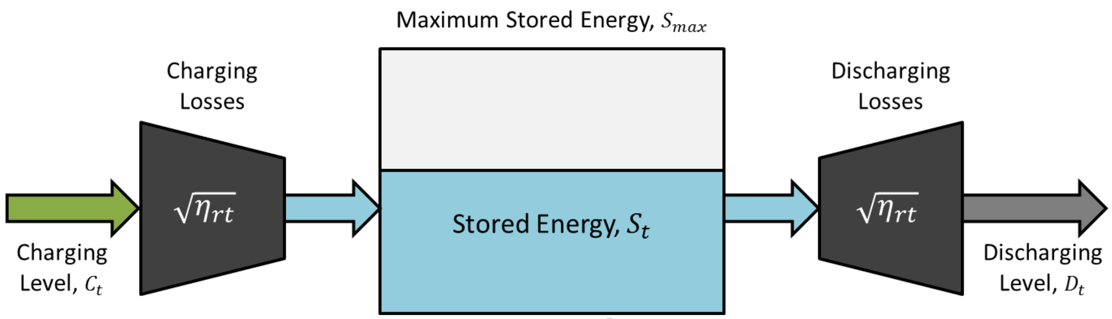


Figure 18. Energy storage model

The storage system acts by storing any renewable energy in excess of the load in each hour (subject to constraints on maximum charging and maximum stored energy) and discharging any stored energy in hours in which the load exceeds the generation from must-run, variable renewable, and energy-limited resources. In PATHWAYS, this functionality is modeled using the following equations in each time step:

Equation 77

$$C_t = \begin{cases} \min\left(\left\{G_t - L_t, C_{max}, \dfrac{S_{max} - S_{t-1}}{\sqrt{\eta_{rt}}}\right\}\right) & \text{if } G_t > L_t \\ 0 & \text{if } G_t \leq L_t \end{cases}$$

$$D_t = \begin{cases} 0 & \text{if } G_t > L_t \\ \min\left(\left\{L_t - G_t, D_{max}, \frac{S_{t-1}}{\sqrt{\eta_{rt}}}\right\}\right) & \text{if } G_t \leq L_t \end{cases}$$

$$S_t = S_{t-1} + \sqrt{\eta_{rt}}C_t - \frac{D_t}{\sqrt{\eta_{rt}}}$$

where G_t is the total generation from must-run, variable renewable, and energy-limited resources, L_t is the load, C_{max} is the maximum charging level, and D_{max} is the maximum discharging level. This heuristic storage dispatch algorithm is intended to alleviate short- and long-term energy imbalances, but it is not intended to represent optimal storage dispatch in an electricity market. The stored energy level begins at 0MWh in the first hour of the first year of the simulation so that energy can only be stored once a storage facility has been built and excess renewables have been used to charge the system. The operating parameters for the equivalent system-wide energy storage device in each year are calculated from the operating parameters of each storage device that is online in that year. The maximum charging level, maximum discharging level, and maximum stored energy are each calculated as the sum of the respective resource-specific parameters across the full set of resources. The round-trip efficiency is calculated using the following approximation. Consider a storage system that spends half of its time discharging and discharges at its maximum discharge level. For this system, the total discharged energy over a period of length T will equal:

Equation 78

$$\int_0^T D_i(t)\,dt = \frac{D_i^{max} \times T}{2}$$

For this system, the total losses can be described by:

Equation 79

$$Losses_i = \int_0^T \left[\frac{D_i(t)}{\eta_i} - D_i(t)\right] dt = \frac{(1-\eta_i)D_i^{max} \times T}{2\eta_i}$$

where η_i is the round-trip losses of storage device i. If the system has several storage devices operating in this way, the total losses are equal to:

Equation 80

$$Losses = \frac{T}{2}\sum_i \frac{1-\eta_i}{\eta_i} D_i^{max} = \frac{T}{2}\left(\sum_i \frac{D_i^{max}}{\eta_i} - D_{max}\right)$$

where D_{max} is the aggregated maximum discharge capacity. The total discharged energy is equal to:

Equation 81

$$Energy = \sum_i \frac{D_i^{max} \times T}{2} = \frac{T}{2} D_{max}$$

The system-wide roundtrip efficiency is therefore approximated by:

Equation 82

$$\frac{Energy}{Energy+Losses} = \frac{D_{max}}{D_{max}+\sum_i \frac{D_i^{max}}{\eta_i} - D_{max}} = \frac{D_{max}}{\sum_i \frac{D_i^{max}}{\eta_i}}$$

The energy storage operational parameters used in this analysis are summarized in Table 44.

Table 44. Energy storage technology operational parameters

Technology	Year 1	Roundtrip Efficiency in Year 1	Year 2	Roundtrip Efficiency in Year 2
Pumped Hydro	2010	70.5%	2020	80%
Batteries	2010	75%	2020	80%
Flow Batteries	2010	75%	2020	80%

3.1.3.7 Dispatchable resources

Dispatchable resources are used to provide the remaining electricity demand after must-run, variable renewable, energy-limited, and storage resources have been used. Dispatch of these resources, which include thermal resources and imports, is approximated using a stack model with heuristics to approximate operational constraints that maintain system reliability. In the stack model, resources are ordered by total operational cost on a $/MWh basis. The operational cost includes: fuel costs equal to the fuel price times the heat rate; carbon costs equal to the price of carbon times the fuel carbon intensity times the heat rate; and input variable operations and maintenance costs. Resources are dispatched in stack order until the remaining load is met. In addition, a minimum generation rule is included to approximate constraints related to voltage, inertia, and transmission flows, which is described below.

- **Minimum thermal constraint** – The user specifies the minimum generation constraint as a fraction of the total hourly gross load in each electric service territory. For each generating technology, the user also specifies whether the resource can contribute to meeting the minimum thermal constraint. The thermal dispatch is then performed in two steps: first, the resources that can contribute to meeting the constraint are dispatched in order of cost to meet the constraint in each hour; next, the remaining resources (including any unused resources that could have contributed to meeting the minimum thermal requirement) are dispatched in order of cost to meet any remaining load.

3.1.3.8 Imports/Exports

Imports are simulated in PATHWAYS by a collection of resources intended to reflect the historical emissions of imported electricity and any predicted changes in the composition of imports going forward, including the expiration of coal contracts. The user specifies the operating mode for each class of imports to best match historical operations. The default assumptions are listed in Table 45 below.

Table 45. Operational modes of each class of imports

Import Classification	Operational Mode	Emissions Intensity (tCO2/MMBtu)	Availability Assumptions
Specified Coal	Must Run	0.0942	2,875MW, rolls off with coal contract expiration by 2030

Import Classification	Operational Mode	Emissions Intensity (tCO2/MMBtu)	Availability Assumptions
Specified BPA	Energy-Limited	0.0427	2,609 MW max, 8,000 GWh/yr, assumed to stay constant going forward
Specified Gas	Dispatchable	0.0529	1,245 MW, capacity adjusts in future years so that total import capacity equals an import limit of 12,620MW
Unspecified	Dispatchable	0.0427	4,809 MW, assumed to stay constant going forward
Unspecified Non-emitting	Energy-Limited	0	1,082MW, represents Hoover and Palo Verde, assumed to stay constant going forward

The model also allows the user to specify a maximum level of exports out of California. The default assumption, based largely on historical exports to the Pacific Northwest, is that California can export up to 1,500 MW in any hour. In its aggregate emissions accounting, PATHWAYS assumes that the emissions associated with any exported power (which are based on the full composition of resources generating in export hours) is exported to neighboring states (ie. not included in California's emissions total). This represents a departure from the current inventory rules, which count all emissions from generators located within the state as well as all emissions from imported electricity. A separate electricity GHG output was also created in the PATHWAYS model to report electricity sector emissions including emissions associated with exported power, to reflect consistency with this aspect of CARB's GHG accounting rules.

3.1.3.9 System imbalances

Once the dispatch has been calculated for each type of resource, the model calculates any remaining energy imbalances. The planning module is designed to ensure that any negative imbalance (potential unserved energy) may be met with conventional demand response resources (the available capacity of which is defined by the user for each case). Demand response dispatch events are tracked and the costs associated with dispatching these resources are added to the operational costs in the revenue requirement (rather than tracking specific demand response program costs). The system might also encounter potential overgeneration conditions, in which the generation exceeds demand. These conditions might arise due to a combination of factors, including low load, high must run generation, high variable renewable generation, and minimum generation operating constraints. Overgeneration conditions are first mitigated with exports to neighboring regions, based on the user-specified maximum export level. For accounting purposes, the exported power emissions rate is approximated as the generation-weighted average emissions rate of all resources generating in each hour. If excess generation remains after accounting for exports then overgeneration is avoided by curtailing renewable resources. Both the delivered renewable energy and the percent of renewable generation that is curtailed in each year are outputs of the model. The model does not procure additional renewable resources to meet RPS targets if renewable curtailment results in less delivered RPS energy than is required for compliance. This renewable overbuild must be decided by the user.

The system operations module outputs include:

- Total annual generation from each technology and fuel type
- Total annual electric sector emissions
- Total electric sector fuel, variable O&M, and carbon costs
- Expected annual delivered renewable energy and percent of renewable generation curtailed

3.1.4 REVENUE REQUIREMENT

The revenue requirement calculation includes the annual fixed costs associated with generation, transmission, and distribution infrastructure as well as the annual variable costs that are calculated in the System Operations Module. The methodology for calculating fixed costs in each year is described below.

3.1.4.1 Generation

Fixed costs for each generator are calculated in each year depending on the vintage of the generator and the user-specified capital cost and fixed O&M cost inputs by vintage for the generator technology. Throughout the financial lifetime of each generator, the annual fixed costs are equal to the vintaged capital cost times a levelization factor plus the vintage fixed O&M costs, plus taxes and insurance. For eligible resources, taxes are net of production tax credits and/or investment tax credits. If the plant's useful lifetime is longer than its financing lifetime, then no levelized capital costs are applied to the years between the end of the financing lifetime and the retirement of the plant (only fixed O&M and variable costs are applied in these years). This methodology is also used to cost energy storage infrastructure and combined heat and power infrastructure. Generator cost assumptions were informed by the E3 report, "Cost and Performance Review of Generation Technologies: Recommendations for WECC 10- and 20-Year Study Process," Prepared for the Western Electric Coordinating Council, Oct. 9, 2012.[26] Cost and financing assumptions for energy storage technologies are summarized in Table 46 below.

Table 46. Capital cost inputs for energy storage technologies

Technology	Capital Cost (2012$/MW)	Financing Lifetime (yrs)	Useful Life (yrs)
Pumped Hydro	2.23M	30	30
Batteries	4.3M	15	15
Flow Batteries	4.3M	15	15

3.1.4.2 Transmission System

Transmission costs are broken into two components: sustaining transmission costs and RPS-driven transmission costs. Sustaining transmission costs include all costs associated with existing transmission infrastructure, incremental transmission build to accommodate load growth, and reliability-related upgrades. These costs are broken into "growth-related" costs, which are driven over time by the annual transmission system peak demand and "non-growth-related" which can escalate at a user-input rate to reflect increasing costs of maintenance and upgrades. The default sustaining transmission cost assumptions are listed in Table 47.

[26] http://www.wecc.biz/committees/BOD/TEPPC/External/E3_WECC_GenerationCostReport_Final.pdf

Table 47. Transmission system cost assumptions

Assumption	Default Value	Notes
Reference Year	2012	
Reference Year Transmission (Tx) Costs	$3.125B/yr	Source: 2012 IOU Revenue Requirements, scaled up by load to rest of state
Growth-Driven Portion of Sustaining Tx Costs	100%	
Escalation Rate for Non-Growth Driven Portion of Sustaining Tx Costs	-	Not used under default settings

RPS-driven costs are approximated from the resource-specific levelized transmission cost adders (in $/MWh) for resources selected from the RPS Calculator database. In each year, the levelized transmission cost adders for the procured renewable resources are multiplied by the procured renewable energy by resource and added to the sustaining transmission annual costs to represent the full costs of the transmission system. Transmission costs associated with renewables built prior to 2012 are not modeled explicitly and are rolled into the sustaining transmission cost component.

3.1.4.3 Distribution System

Distribution costs are broken into sustaining distribution costs and distributed generation-driven costs. Sustaining distribution costs are driven by the growth in the distribution peak with a 5-yr lag incorporated to better fit historical distribution components of the IOU revenue requirements. In each year the growth rate of the sustaining distribution cost is approximated by:

Equation 83

$$c_y^{Dx} = \left[c_{y-1}^{Dx}\right]^{r_{y-5}+k}$$

where r_{y-5} is the growth rate of the distribution system peak in year $y - 5$, k is a constant equal to 1.021 (based on historical data), and c_{2012}^{Dx} is the total distribution component of the IOUs' revenue requirements in 2012, scaled up to the rest of the state by load ($12.218B). Distributed generation costs are approximated as a fixed input $/MWh times the total rooftop solar generation in each year.

3.1.5 COST ALLOCATION

PATHWAYS also allocates electricity costs to each sector based on an embedded cost framework designed to accommodate new phenomena in the electricity sector like flexible loads, energy storage, and fuel production loads. In this framework, the average electricity rate in each sector (residential, commercial, industrial, transportation, and fuel production) depends on the sector's contribution to the need for: conventional generation investments and fixed O&M costs; fuel and variable O&M costs for conventional generation; renewable resource procurement; transmission investments; distribution system upgrade costs; distributed generation-related costs; and other costs, like program costs and fees. The methods for calculation of these contributions are summarized in Table 48.

Table 48. Electricity cost allocation methodology

Cost Component	Methodology for Allocation by Sector	Notes
Conventional Generation Fixed Costs	Percent contribution of the sector-wide load shape to the peak demand for conventional generation times the total conventional generation fixed costs	
Conventional Generation Fuel and Variable O&M Costs	Product of hourly average variable costs ($/MWh) and hourly demand	
Renewable Generation Costs	Percent contribution of the sector-wide annual energy demand to the total annual energy demand times the total renewable generation cost	Costs include renewable-driven transmission costs and energy storage costs for balancing
Transmission Costs	Percent contribution of the sector-wide load shape to the peak demand on the transmission system (net of distribution and sub-transmission level generation) times the total annual sustaining transmission costs	Excludes renewable-driven transmission costs
Distribution Costs	Percent contribution of the sector-wide load shape to the peak demand on the distribution system times the total annual sustaining distribution costs	Excludes distributed generation-driven transmission costs
Distributed Generation Interconnection Costs	Percent of distributed PV installed capacity by sector times the total distributed generation-related distribution costs	
Other (programs and fees)	Percent contribution of sector-wide annual energy demand to total annual energy demand	

The resulting cost allocation is shown for the Reference Case in Figure 19, juxtaposed against the 2013 historical allocation of electricity costs in the IOUs.

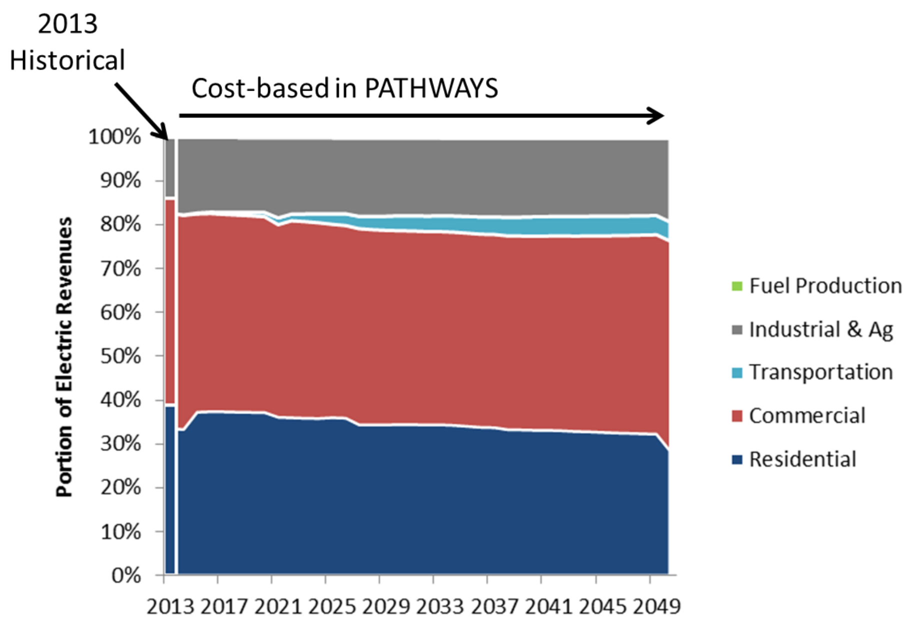


Figure 19. Cost allocation results for the Reference Case, shown against the 2013 average cost allocation across the IOUs

The allocated electricity system costs by sector are then divided by the sector-specific electricity demand (gross demand, as electricity system costs include the costs of behind-the-meter CHP and rooftop PV resources) to produce an average electricity rate by sector. These average rates flow through each sector module to calculate sector-wide energy costs.

3.1.6 EMISSIONS

The electricity module also calculates an average emissions rate for electricity generation based on the emissions rates specified for each generating technology, the energy generated by each technology in each year, and the carbon capture fraction of each technology (if CCS is employed). The average emissions rate, E, for electricity is therefore:

Equation 84

$$E = \frac{\sum_{k,t} P_{k,t} \times e_k \times \left(1 - f_k^{CC}\right)}{Total\ Sales}$$

where $P_{k,t}$ is the power output in hour t (within the year of interest), e_k is the emissions rate, which is equal to the carbon intensity of the fuel times the heat rate, and f_k^{CC} is the carbon capture fraction for technology k. This emissions rate is applied to the electricity demand associated with each sector to determine the contribution of electricity emissions to each sector's total emissions.

3.1.6.1 CHP emissions accounting

One exception to this approach is the emissions accounting for combined heat and power (CHP) resources. The electricity sector models gross electric generation from CHP resources (both the power used onsite and the power exported to the grid) because PATHWAYS tracks gross electricity demand by sector. For emissions accounting, the average heat rate of existing CHP facilities is tuned to match the total historical CHP emissions in 2012 (including all inventoried emissions allocated to the electricity sector as well as the commercial and industrial sectors). In PATHWAYS, the total emissions obtained using this gross heat rate must then be allocated to the electricity sector based on total electricity generation and to the sectors in which CHP resources are providing heating services. The portion allocated to electricity, f_{elec}, is determined based on the power-to-heat ratio, r_{p2h}, of the CHP resources by technology type, according to:

Equation 85

$$f_{elec} = \frac{r_{p2h}}{1 + r_{p2h}}$$

The assumed power-to-heat ratios (based on EIA Form 923) are listed in Table 49.

Table 49. CHP technology power to heat ratios (EIA Form 923)

CHP Technology	Power-to-Heat Ratio (Btu Electric/Btu Thermal)
Existing CHP	1.23
Phosphoric Acid Fuel Cell (PAFC) - 200 kW	1.17
PAFC – 400 kW	1.17
Molten Carbonate Fuel Cell (MCFC) - 300 kW	2.13
MCFC – 1,500 kW	2.15
Gas Turbine – 3,000 kW	0.68
Gas Turbine – 10 MW	0.73

CHP Technology	Power-to-Heat Ratio (Btu Electric/Btu Thermal)
Gas Turbine – 40 MW	1.07
Microturbine – 65 kW	0.54
Microturbine (multi-unit) – 250 kW	0.71
Reciprocating Engine (rich burn) – 100 kW	0.56
Reciprocating Engine (clean burn) – 800 kW	0.79
Reciprocating Engine (clean burn) – 3,000 kW	0.97
Reciprocating Engine (clean burn) – 5,000 kW	1.12

3.1.6.2 Exports emissions accounting

PATHWAYS also allows limited exports of electricity out of California to meet demands elsewhere in the Western Interconnect when California would otherwise curtail renewable energy. The default assumption is that up to 1,500 MW of power can be exported out of California, based largely on historical exports to the Pacific Northwest.[27] In hours in which California exports power, PATHWAYS subtracts the emissions associated with those exports (assuming that the exported energy has the same emissions intensity as the energy used in California during the hour) from the total electricity emissions. This represents a departure from current GHG inventory accounting rules, but has a minimal

[27] Note that historically California has not net exported under any conditions because as power is sent from California to the Pacific Northwest, it is also being imported from the Southwest into California. The assumption of limited net exports out of California represents a significant departure from historical flows across the Western Interconnect and requires more detailed study.

impact on electricity-wide emissions given the relatively stringent limit placed on exports relative to California's total electricity demand.

3.1.7 LOAD SHAPE DATA SOURCES

The load shapes obtained for this analysis and the corresponding weather year or weather data source are listed in Table 50.

Table 50. Input load shapes and sources

Load Shape	Sector/Subsector	Source	Identifier	Region	Weather Year or Source
1	Residential Water Heating	DEER2008		PG&E	2008 Title 24
2	Residential Water Heating	DEER2008		SCE	2008 Title 24
3	Residential Water Heating	DEER2008		SDG&E	2008 Title 24
4	Residential Space Cooling	DEER2008		PG&E	2008 Title 24
5	Residential Space Cooling	DEER2008		SCE	2008 Title 24
6	Residential Space Cooling	DEER2008		SDG&E	2008 Title 24
7	Residential Space Cooling	DEER2011	HVAC_Eff_AC	PG&E	2008 Title 24
8	Residential Space Cooling	DEER2011	HVAC_Eff_AC	SCE	2008 Title 24
9	Residential Space	DEER2011	HVAC_Eff_AC	SDG&E	2008 Title 24

Load Shape	Sector/Subsector	Source	Identifier	Region	Weather Year or Source
	Cooling				
10	Residential Lighting	DEER2011	Indoor_CFL_Ltg	PG&E	2008 Title 24
11	Residential Lighting	DEER2011	Indoor_CFL_Ltg	SCE	2008 Title 24
12	Residential Lighting	DEER2011	Indoor_CFL_Ltg	SDG&E	2008 Title 24
13	Residential Clothes Washing	DEER2011	ClothesWasher	PG&E	2008 Title 24
14	Residential Clothes Washing	DEER2011	ClothesWasher	SCE	2008 Title 24
15	Residential Clothes Washing	DEER2011	ClothesWasher	SDG&E	2008 Title 24
16	Residential Dishwashing	DEER2011	Dishwasher	PG&E	2008 Title 24
17	Residential Dishwashing	DEER2011	Dishwasher	SCE	2008 Title 24
18	Residential Dishwashing	DEER2011	Dishwasher	SDG&E	2008 Title 24
19	Residential Refrigeration	DEER2011	RefgFrzr_HighEff	PG&E	2008 Title 24
20	Residential Refrigeration	DEER2011	RefgFrzr_HighEff	SCE	2008 Title 24
21	Residential Refrigeration	DEER2011	RefgFrzr_Recyc-UnConditioned	PG&E	2008 Title 24
22	Residential Refrigeration	DEER2011	RefgFrzr_Recyc-UnConditioned	SCE	2008 Title 24

Load Shape	Sector/Subsector	Source	Identifier	Region	Weather Year or Source
23	Residential Refrigeration	DEER2011	RefgFrzr_Recyc-UnConditioned	SDG&E	2008 Title 24
24	Residential Clothes Drying	DEER2008		PG&E	2008 Title 24
25	Residential Cooking	BEopt		CZ3	BEopt
26	Residential Other	BEopt		CZ3	BEopt
27	Residential Space Heating	BEopt		CZ3	BEopt
28	Residential Space Heating	BEopt		CZ6	BEopt
29	Residential Space Heating	BEopt		CZ10	BEopt
30	Residential Space Heating	BEopt		CZ12	BEopt
31	Commercial Water Heating	DEER2008		PG&E	2008 Title 24
32	Commercial Water Heating	DEER2008		SCE	2008 Title 24
33	Commercial Water Heating	DEER2008		SDG&E	2008 Title 24
34	Commercial Space Heating	CEUS			Historical - 2002
35	Commercial Space Cooling	DEER2011	HVAC_Chillers	PG&E	2008 Title 24

Load Shape	Sector/Subsector	Source	Identifier	Region	Weather Year or Source
36	Commercial Space Cooling	DEER2011	HVAC_Split-Package_AC	PG&E	2008 Title 24
37	Commercial Space Cooling	DEER2011	HVAC_Chillers	SCE	2008 Title 24
38	Commercial Space Cooling	DEER2011	HVAC_Split-Package_AC	SCE	2008 Title 24
39	Commercial Space Cooling	DEER2011	HVAC_Chillers	SDG&E	2008 Title 24
40	Commercial Space Cooling	DEER2011	HVAC_Split-Package_AC	SDG&E	2008 Title 24
41	Commercial Lighting	CEUS			Historical - 2002
42	Commercial Lighting	DEER2011	Indoor_CFL_Ltg	PG&E	2008 Title 24
43	Commercial Lighting	DEER2011	Indoor_Non-CFL_Ltg	PG&E	2008 Title 24
44	Commercial Lighting	DEER2011	Indoor_CFL_Ltg	SCE	2008 Title 24
45	Commercial Lighting	DEER2011	Indoor_Non-CFL_Ltg	SCE	2008 Title 24
46	Commercial Lighting	DEER2011	Indoor_CFL_Ltg	SDG&E	2008 Title 24
47	Commercial Lighting	DEER2011	Indoor_Non-CFL_Ltg	SDG&E	2008 Title 24
48	Commercial Cooking	CEUS			Historical - 2002

Load Shape	Sector/Subsector	Source	Identifier	Region	Weather Year or Source
49	Streetlights	PG&E Static	LS1	PG&E	Historical - 2010
50	Agriculture	PG&E Static	AG1A	PG&E	Historical - 2010
51	Agriculture	PG&E Static	AG1B	PG&E	Historical - 2010
52	Agriculture	PG&E Static	AG4A	PG&E	Historical - 2010
53	Agriculture	PG&E Static	AG4B	PG&E	Historical - 2010
54	Agriculture	PG&E Static	AG5A	PG&E	Historical - 2010
55	Agriculture	PG&E Static	AG5B	PG&E	Historical - 2010
56	Agriculture	PG&E Static	AGVA	PG&E	Historical - 2010
57	Agriculture	PG&E Static	AGRA	PG&E	Historical - 2010
58	Industrial	PG&E Dynamic	A6	PG&E	Historical - 2010
59	Industrial	PG&E Dynamic	E19P	PG&E	Historical - 2010
60	Industrial	PG&E Dynamic	E19V	PG&E	Historical - 2010
61	Industrial	PG&E Dynamic	E20P	PG&E	Historical - 2010

3.1.8 MODEL DATA INPUTS AND REFERENCES

Category	Data source
Hourly end-use electric load shapes	Residential & commercial: Primarily DEER2008 and DEER 2011, BEopt for residential space heating, cooking and other, CEUS for commercial space heating, lighting and cooking. Agriculture & Industrial: PG&E 2010 load shape data
Hourly renewable generation shapes	Solar PV: simulated using System Advisor Model (SAM), PV Watts Concentrated solar power: simulated using System Advisor Model (SAM) Wind: Western Wind Dataset by 3TIER for the first Western Wind and Solar Integration Study performed by NREL http://wind.nrel.gov/Web_nrel/
Hydroelectric characteristics	Monthly hydro energy production data from historical EIA data reported for generating units, http://www.eia.gov/electricity/data/eia923/ Daily minimum and maximum hydro generation limits based on CAISO daily renewable watch hydro generation data http://www.caiso.com/market/Pages/ReportsBulletins/DailyRenewablesWatch.aspx
Import/export limits	Guidance from CAISO and subset of historical path flow data over Path 46, PDCI, and COI. Consistent with assumptions used in base case of CA electric utility/E3 study "Investigating a

	Higher RPS Study" (2013).
Existing generation & heat rates	TEPPC 2022 Common Case, and "Capital cost review of power generation technologies, recommendations for WECC's 10- and 20-year studies" **http://www.wecc.biz/committees/BOD/TEPPC/External/2014_TEPPC_Generation_CapCost_Report_E3.pdf**
Renewable generation & transmission capital costs	CPUC RPS Calculator, updated 2014
Thermal generation capital costs	"Capital cost review of power generation technologies, recommendations for WECC's 10- and 20-year studies" (E3, March 2014) **http://www.wecc.biz/committees/BOD/TEPPC/External/2014_TEPPC_Generation_CapCost_Report_E3.pdf**
Energy storage capital costs	"Cost and performance data for power generation technologies," (Black and Veatch, prepared for NREL, February 2012) **http://bv.com/docs/reports-studies/nrel-cost-report.pdf**
Power plant financing assumptions	"Capital cost review of power generation technologies, recommendations for WECC's 10- and 20-year studies" (E3, March 2014) **http://www.wecc.biz/committees/BOD/TEPPC/External/2014_TEPPC_Generation_CapCost_Report_E3.pdf**

Current electric revenue requirement	Revenue requirement by component, historical FERC Form 1 data, **https://www.ferc.gov/docs-filing/forms.asp**

3.2 Pipeline gas

The term pipeline gas is used here and throughout the PATHWAYS model to acknowledge the potential of the pipeline to deliver products other than traditional natural gas. PATHWAYS models multiple decarbonization strategies for the pipeline including biomass conversion processes, hydrogen, and synthetic methane from power-to-gas processes. Below is a description of the commodity products included in the pipeline in our decarbonization scenarios as well as a discussion of the approach to modeling delivery charges for traditional as well as compressed and liquefied pipeline gas.

PATHWAYS models the California pipeline system's delivery of pipeline gas as well as compressed pipeline gas, and liquefied pipeline gas for transportation uses. We model these together in order to assess the capital cost implications of changing pipeline throughput volumes. Delivery costs of pipeline gas are a function of capital investments at the transmission and distribution-levels and delivery rates can be broadly separated into core (usually residential and small commercial) and non-core (large commercial, industrial, and electricity generation) categories. Core service traditionally provides reliable bundled services of transportation and sales compared to non-core customers with sufficient volumes to justify transportation-only service. The difference in delivery charges can be significant. In September, 2013 the average U.S. delivered price of gas to an industrial customer was $4.39/thousand cubic feet compared to $15.65/thousand cubic feet for residential customers （United States Energy Information Administration，2013）． This difference is driven primarily by the difference in delivery charges for different customer classes.

To model the potential implications of large changes in gas throughput on delivery costs, we use a simple revenue requirement model for each California IOU. This model includes total revenue requirements by core and non-core customer designations, an estimate of the real escalation of costs (to account for increasing prices of commodities, labor, engineering, etc.) of delivery services, an estimate of the remaining capital asset life of utility assets, and the percent of the delivery rate related to capital investments. These last two model inputs influence the rate at which the rate base depreciates, which will affect the delivery rates under scenarios where there is a rapid decline in pipeline throughput that outpaces capital depreciation. We assume that 50% of the revenue requirement of a gas utility is related to throughput growth and that capital assets have an average 30-year remaining financial life. This means that the revenue requirement at most could decline 1.7% per year and that any decline in throughput exceeding this rate would result in escalating delivery charges for remaining customers. This is a result of utilities being forced to recover revenue from a declining amount of throughput, increasing rates for remaining customers and potentially encouraging fuel switching, thus accelerating the process. These costs will have to be recovered and so need to continue to be represented even in scenarios where there are rapid declines in pipeline throughput.

3.3 Natural Gas

Natural gas price forecasts are taken from the EIA's Annual Energy Outlook 2013 （EIA, 2013） reference case scenario.

3.3.1 COMPRESSED PIPELINE GAS

We model the costs of compression facilities at $.87/Gallons of Gasoline Equivalent (GGE) based on an average of cost ranges reported by Argonne National Laboratory （Argonne National Laboratory, 2010）. Additionally, we model the electricity use of compressing facilities at 1 kWh per GGE based on the same report. These inputs affect the emissions associated with compressed pipeline gas relative to pipeline gas.

3.3.2 LIQUEFIED PIPELINE GAS

We model the non-energy costs of liquefaction facilities at $.434/Gallons of Gasoline Equivalent (GGE) based on an analysis by the Gas Technology Institute （Gas Technology Institute, 2004）. Additionally, we model the electricity use of liquefaction facilities using electric drive technologies at $3.34 kWh per GGE based on the same report. These inputs affect the emissions associated with liquefied pipeline gas relative to pipeline gas.

3.4 Liquid Fossil Fuels

Liquid fuels are primarily fuels used for transportation and include diesel, gasoline, jet-fuel, and hydrogen as well as LPG. We model biofuel processes for both diesel fuel as well as gasoline that are described further in section 3.7.2. Jet-fuel and LPG are only supplied as conventional fossil fuels. The sections below discuss conventional fossil price projections as well as liquid hydrogen delivery.

Conventional fossil fuel price projections are taken from the AEO 2013 reference case scenario. They include both commodity as well as delivery costs for fuels delivered to the Pacific census division.

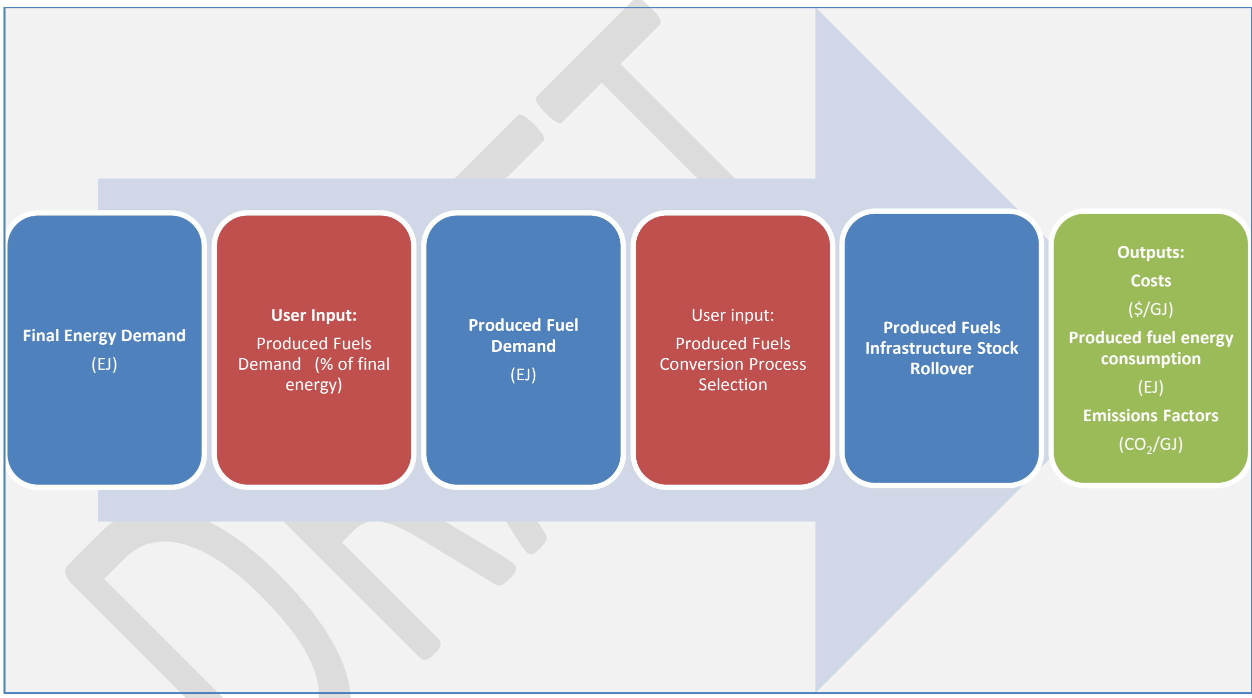
3.5 Refinery and Process Gas; Coke

We do not model any costs associated with refinery and process gas. We do model the costs of coke from the 2013 AEO Reference Case scenario （EIA, 2013）.

3.6 Synthetically produced fuels

PATHWAYS' Produced Fuel Module calculates the energy demand, cost, and emissions associated with hydrogen and synthetic methane. Demand for these fuels is combined with user-selected conversion processes to drive demand for produced fuels production facilities. PATHWAYS uses vintage-specific cost and conversion efficiency inputs to calculate stock-average production cost and efficiency values, drawing on a stock rollover mechanism. These average cost and efficiency values are then used, along with final demand for produced fuels, to calculate the energy demand (GJ of energy input), cost ($/GJ), and emissions intensity (kgCO_2/GJ) of produced fuels.

Figure 20. Produced Fuels Module Framework



3.6.1 CONVERSION PROCESSES FOR PRODUCED FUELS

In PATHWAYS, hydrogen can be produced through three conversion pathways: (1) electrolysis, which uses electricity as an energy source and water as a source of hydrogen; (2) steam reforming, which uses natural gas as an energy and hydrogen source; (3) steam reforming with carbon capture and storage, which captures the CO_2 emitted from natural gas in the reforming process. The share of hydrogen demand met by each of these pathways is user defined. Synthetic methane is only produced through methanation, a process that converts hydrogen produced through electrolysis and CO2 into methane. Table 51 shows the assumed cost and efficiency parameters for these four conversion processes.

Table 51. Conversion process inputs

Produced fuel type (t)	Conversion process (c)	Input energy (i)	Conversion efficiency (CE)	Levelized annual capital costs (PF.ACC)	Levelized non-energy operating Costs (PF.OCC)	CO_2 capture ratio (CC)
Hydrogen	Electrolysis	Electricit y	65%-78% (LHV)	$0.65-1.53/kg-year	$0.05/kg	N/A
Hydrogen	Reformation	Natural Gas	62%-71% (LHV)	$0.54-0.68/kg-year	$0.17/kg	N/A
Hydrogen	Reformation w/CCS	Natural Gas	62%-71% (LHV)	$0.47-0.59/kg-year	$0.17/kg	0.9
Synthetic Methane	Methanat-ion	Electricit y	52%-63% (HHV)	$7.6-18.5/MMB TU-year	$6.5/MMB TU	N/A

3.6.2 DEMAND FOR PRODUCED FUELS

Final demand for produced fuels (PFD, in GJ/yr) is determined both directly by final demand sectors (e.g., hydrogen demand in the transportation sector), and indirectly through demand for energy carriers that contain produced fuels (e.g., residential demand for pipeline gas that contains hydrogen and synthetic methane). The shares of produced fuels in a given final energy carrier during a given timeframe are user-determined; users input shares in a start and end year and PATHWAYS linearly interpolates annual shares between these points.[28] Each produced fuel is tracked in PATHWAYS by conversion process.

[28] When produced fuels are used as final energy carriers, SF is set to 100%. Before the user-specified start year, SF is set to zero.

Equation 86

$$PFD_{tcy} = \sum_{e} FEC_{ey} \times SF_{tey} \times PF_{tcy}$$

$$SF_{tey} = SF_{tey_0} + \frac{SF_{tey_T} - SF_{tey_0}}{y_T - y_0} \times (y - y_0)$$

New Subscripts

t	produced fuel type	hydrogen, synthetic methane
c	conversion process	electrolysis, reforming, reforming w/ CCS, methanation
E	final energy carrier	pipeline gas, hydrogen, electricity
Y	year	is the model year (2014 to 2050)
y_0	start year	user input value, between 2014 and 2049
y_T	end year	user input value, between 2015 and 2050

New Variables

PFD_{tcy}	Final demand for produced fuel type t and conversion process type c in year y
FEC_{ey}	Final energy consumption of final energy carrier e in year y
SF_{tey}	Share of fuel type t in final energy carrier e (e.g., share of synthetic methane in pipeline gas) in year y
PF_{tcy}	Share of fuel type t from conversion process c (e.g., share of hydrogen produced through electrolysis) in year y

3.6.3 STOCK ROLLOVER MECHANICS FOR PRODUCED FUELS

The Produced Fuels Module includes a stock-rollover mechanism that governs changes in the composition of produced fuels' infrastructure over time, including costs and efficiency of production. The mechanism tracks production facility vintages — the year in which a facility was constructed — by census region. At the end of each year, PATHWAYS retires or rebuilds some amount of a given production facility for conversion type c in a given region ($S.RET_y$), by multiplying the initial stock of each vintage (S_{vy}) by a replacement coefficient (β_{vy}).

Equation 87

$$S.RET_{tcvy} = S.EXT_{tcvy} \times \beta_{vy}$$

New Variables

$S.RET_{ctvy}$	is the amount of existing production facilities of vintage v of conversion process c to produce fuel type t retired or replaced in year y
β_{vy}	is a replacement coefficient for vintage v in year y

The replacement coefficients are generated by a survival function that uses Poisson distribution, with a mean (λ) equal to the expected useful life of the facility.

Equation 88

$$\beta_{vy} = e^{-\lambda} \frac{\lambda^{y-v+1}}{(y-v+1)!}$$

Growth in final demand for produced fuel is used to project the growth of production facility stock (maximum EJ of production capacity per year), using an assumed capacity factor.

Equation 89

$$S.GRW_{tcy} = \frac{PFD_{tcy} - PFD_{tcy-1}}{CF_{tc}}$$

New Variables

S.GRW$_{tcy}$	Growth in stock of production facilities producing fuel type t with conversion process c in year y
CF$_{tc}$	Capacity factor of production facilities producing fuel type t with conversion process c

At the beginning of the following year (y+1), PATHWAYS replaces retired stock and adds new stock to account for growth in produced fuels. The vintage of these new stock additions is then indexed to year y+1.

Equation 90

$$S.NEW_{tcy+1} = \sum_{v} S.RET_{tcvy} + S.GRW_{tcy}$$

New Variables

S.NEW$_{tcy+1}$	New stock of production facilities producing fuel type t with conversion process c in year y+1

3.6.4 ENERGY CONSUMPTION OF PRODUCED FUELS

Because produced fuels are derived from other energy carriers, the Produced Fuels Module receives its energy input from energy supply modules (e.g., the Electricity Module). These energy supply modules must provide the energy both to meet final demand for produced fuels and to cover the energy lost in conversion processes. The calculated consumption of produced fuel energy inputs is used in other energy supply modules, like the Electricity Module. These energy supply modules must meet the demand from final energy modules as well as this energy demand from produced fuels processes. The equation used to calculate the energy demand from produced fuels processes is shown below.

Equation 91 Produced fuel energy consumption

$$PF.EC_{ity} = \sum_{c}\sum_{v} PFD_{cy} * CE_{vce} * \frac{S.EXT_{vcy}}{S.EXT_{cy}} * P_{iy} * PF_{ctv}$$

New Subscripts

i	energy input	electricity, natural gas

New Variables

$PF.EC_{ity}$	is the energy consumption of input energy type i for produced fuel type t in year y
CE_{tcv}	Conversion efficiency of vintage v production facilities producing fuel type t with conversion process c
$S.EXT_{tcvy}$	Existing stock of vintage v production facilities producing fuel type t with conversion process c in year y
$S.EXT_{tcy}$	Existing stock of production facilities producing fuel type t with conversion process c in year y

3.6.5 TOTAL COST OF PRODUCED FUELS

Total produced fuel costs (PF.T, $ per GJ of fuel produced) are composed of the fixed capital costs (PF.C), energy costs (PF.E), and non-energy operating costs (PF.O) of production facilities.

Equation 92

$$PF.T_{ty} = PF.C_{ty} + PF.E_{ty} + PF.O_{ty}$$

New Variables

$PF.T_{ty}$	Total cost ($/GJ) of produced fuel type t in year y
$PF.C_{ty}$	Capital cost ($/GJ) of produced fuel type t in year y
$PF.E_{ty}$	Energy cost ($/GJ) of produced fuel type t in year y
$PF.O_{ty}$	Operating cost ($/GJ) of produced fuel type t in year y

Annualized capital costs for produced fuels (PF.C) are indexed by vintage, as shown in Equation 93.

Equation 93

$$PF.C_{ty} = \sum_{c}\sum_{v}\frac{PF.ACC_{tcv} \times S.EXT_{tcvy}}{PFD_{tcy}}$$

New Variables

$PF.ACC_{tcv}$	Annualized unit capital cost of vintage v production facilities producing fuel type t with conversion process c

Energy costs for produced fuels (PF.E) are determined by the cost of energy inputs divided by vintage-weighted conversion efficiency.

Equation 94

$$PF.E_{ty} = \sum_{c}\sum_{i}\frac{P_{iy} \times PF.EC_{ity}}{PFD_{tcy}}$$

New Variables

P_{iy}	Price of input energy i in year y

Non-energy operating costs for produced fuels (PF.O) are based on vintage-specific operating costs.

Equation 95

$$PF.O_{ty} = \sum_{c}\sum_{v}\frac{PF.AOC_{tcv} \times S.EXT_{tcvy} \times CF_{tc}}{PFD_{tcy}}$$

New Variables

$PF.AOC_{tcv}$	Annual non-energy operating cost for vintage v production facilities producing fuel type t with conversion process c

3.6.6 EMISSIONS FACTORS FOR PRODUCED FUELS

The emissions factor for produced fuels is a function of the total emissions associated with the input energy to the produced fuels divided by the total fuel production.

Equation 96

$$CEF_{ty} = \sum_c \sum_i \frac{PTD_{tciy} \times CEF_{iy} \times CC_c}{PFD_{tcy}}$$

New Variables

CEF_{ty}	CO_2 emissions factor of produced fuel type t in year y
PTD_{tciy}	Total energy demand for fuel type t produced with fuel type c and energy input i in year y
CEF_{iy}	CO_2 emissions factor for input energy i in year y
CC_c	is the CO_2 emissions capture ratio of conversion process c

3.6.7 MODEL DATA INPUTS AND REFERENCES

Table 52: Synthetically produced fuels model inputs

Title	Units	Description	Reference
P2G Prod Inputs	Various	Conversion process inputs for power-to-gas methanation: Plant Life; Capital Costs, Efficiency, Feedstock, Non-energy operating costs	（Svenskt Gastekniskt Center AB ，2013）
H2 Production Input	Various	Conversion process inputs for hydrogen: Plant Life; Capital Costs, Efficiency, Feedstock, Non-energy operating costs	（Department of Energy, 2014）

3.6.8 REFERENCES

Department of Energy. H2A Analysis. 2014.

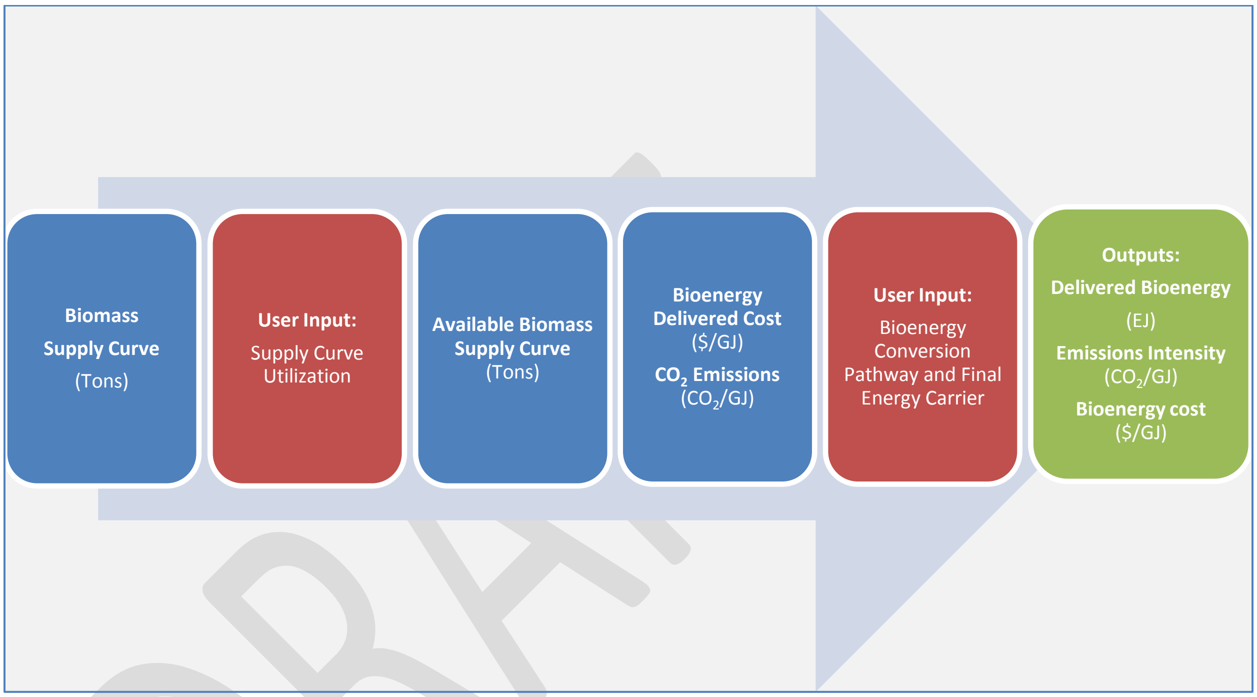
http://www.hydrogen.energy.gov/h2a_analysis.html (accessed 2014).

Svenskt Gastekniskt Center AB. Power-to-gas -- A Technical Review. Technical Report, Malmo: Svenskt Gastekniskt Center AB, 2013.

3.7 Biomass and Biofuels

PATHWAYS' bioenergy module calculates the energy potential, delivered cost, and associated emissions from the production of biomass-based energy products. Drawing from a biomass supply curve, users select and allocate biomass resources to feedstock-specific conversion pathways (e.g., gasification of cellulosic feedstocks) and final energy carriers (e.g., pipeline gas). These bioenergy-based energy carriers are then used by end use sectors as alternatives to fossil fuels.

Figure 21 Basic Module Framework



3.7.1 BIOMASS SUPPLY CURVE

The biomass supply curve is based on the economic resource potential of 32 different feedstocks in the 48 continental United States at 11 different price points, derived from data used to support the U.S. Department of Energy's Billion-Ton Update （Oak Ridge National Laboratory，2011）. This results in nearly 17,000 possible feedstock-state-price combinations, a level of granularity that allows for the inclusion or exclusion of different resource types and the ability to constrain the sourcing of biomass from certain geographical regions.

Within the total U.S. biomass supply (interpolated between 2013 and 2030 and held constant thereafter), users can adjust the share of biomass resources available for consumption in a single state or region using different allocation factors (AF). Possible allocation factors include population share, gross domestic product share, and vehicle miles traveled share, all of which are calculated on a time-invariant basis using a base year. Users can also adjust the amount of the total available biomass resource actually available in initial and final model years using a utilization factor (UF). The utilization factor adjusts the quantity, but not the price, of a given quantity-price combination on the supply curve. For each year, PATHWAYS calculates the total available resource of each biomass feedstock in each state (AB) by linearly interpolating between trajectory start year and trajectory end-year utilization factor values, as shown in Equation 97. In years before the start year, the utilization factor is set to 0. In years after the end year, the utilization factor remains constant at the end year value.

Equation 97

$$AB_{fsy} = TB_f \times AF_s \times UF_y$$

$$UF_y = UF_{y_0} + \frac{UF_{y_T} - UF_{y_0}}{y_T - y_0} \times (y - y_0)$$

New Subscripts

f	feedstock	biomass feedstock type (32 feedstocks)
s	state	U.S. state (48 continental states)
y	year	is the model year (2014 to 2050)
y_0	start year	user input start year for utilization factor (between 2014 and 2049)
y_T	end year	user input end year for utilization factor (between 2015 and 2050)

New Variables

AB_{fsy}	Available biomass feedstock type f in state s and year y
TB_f	Total nationally available biomass feedstock type f
AF_s	Allocation factor for state s
UF_y	Utilization factor of biomass resources in year y

3.7.2 CONVERSION TO FINAL ENERGY AND EMISSIONS

3.7.2.1 Conversion Pathways

As shown in Table 53, the 32 feedstocks are aggregated into four categories, in order to match feedstocks with bioenergy conversion paths and final energy carriers.

Table 53 Feedstock name and category

Feedstock name	Feedstock category
Cotton gin trash	Cellulosic
Cotton residue	Cellulosic
Orchard and vineyard prunings	Cellulosic
Rice hulls	Cellulosic
Rice straw	Cellulosic
Sugarcane trash	Cellulosic
Wheat dust	Cellulosic
Barley straw	Cellulosic
Corn stover	Cellulosic
Oat straw	Cellulosic
Sorghum stubble	Cellulosic
Wheat straw	Cellulosic
Annual energy crop	Cellulosic
Perennial grasses	Cellulosic
Ethanol from corn	Cellulosic
MSW sources, agricultural	Cellulosic
Soy oil derived biodiesel	Lipid
Waste oil-derived biodiesel	Lipid
Manure	Manure
Mill residue, unused secondary	Woody Cellulosic
Mill residue, unused primary	Woody Cellulosic
Urban wood waste, construction and demolition	Woody Cellulosic
Urban wood waste, municipal solid waste	Woody Cellulosic
Composite	Woody Cellulosic
Other removal residue	Woody Cellulosic
Conventional wood	Woody Cellulosic
Treatment thinnings, other forest lands	Woody Cellulosic
Coppice and non-coppice woody crops	Woody Cellulosic
Fuelwood	Woody Cellulosic
Mill residue	Woody Cellulosic

Feedstock name	Feedstock category
Pulping liquors	Woody Cellulosic
MSW sources, forest	Woody Cellulosic

PATHWAYS allows users to choose from multiple conversion pathway-final energy carrier combinations for each of the four feedstock categories. Table 54 shows the conversion pathways included in PATHWAYS for each feedstock category and final energy carrier.

Table 54 Feedstock to final energy conversion pathways

	Feedstock Category			
Final Energy Carrier	**Cellulosic**	**Lipid**	**Manure**	**Woody Cellulosic**
Pipeline Gas	Anaerobic Digestion		Anaerobic Digestion	Thermal Gasification
Electricity	Combustion		Combustion	Combustion
Gasoline	Hydrolysis, Pyrolysis			Hydrolysis, Pyrolysis
Diesel	Fischer-Tropsch, Pyrolysis	Hydrolysis		Fischer-Tropsch, Pyrolysis
Kerosene Jet Fuel	Pyrolysis	Hydrolysis		Pyrolysis

Table 55 shows efficiencies used in PATHWAYS for the conversion pathway-final energy carrier combinations shown in Table 54. Energy losses in the bioenergy module are calculated as losses of primary bioenergy, which assumes that all energy inputs to conversion processes are biomass-based.

Table 55 Biomass conversion efficiencies

Feedstock Category	Conversion Pathway	Efficiency	Supporting Data Sources
All Cellulosic	Thermal Gasification - Pipeline Gas	66%	（Thermo-economic process model for thermochemical production of Synthetic Natural Gas (SNG) from lignocellulosic biomass, 2009）；（Woody biomass-based transportation fuels – A comparative techno-economic study, 2014）
All Cellulosic	Combustion - Electricity	100%[29]	
All Cellulosic	Hydrolysis - Gasoline	30%-45%	（Techno-economic comparison of process technologies for biochemical ethanol production from corn stover, 2010）；（Aden, 2008）；（National Renewable Energy Laboratory, 2011）
All Cellulosic	Pyrolysis - Gasoline	36%	（Techno-economic analysis of biomass fast pyrolysis to transportation fuels, 2010）
All Cellulosic	Fischer-Tropsch - Diesel	42%	（Production of FT transportation fuels from biomass; technical options, process analysis and optimisation, and development potential, 2004）；（Large-scale gasification-based coproduction of fuels and electricity from switchgrass, 2009）；（Techno-economic analysis of biomass-to-liquids production based on gasification, 2010）
All Cellulosic	Pyrolysis - Diesel	36%	（Techno-economic analysis of biomass fast pyrolysis to transportation fuels, 2010）
All Cellulosic	Pyrolysis - Jet Fuel	36%	（Techno-economic analysis of biomass fast pyrolysis to transportation fuels, 2010）
Manure	Anaerobic Digestion - Pipeline Gas	63%	（Krichet al., 2005）

[29] The efficiency penalty of biomass to electricity is assessed in the electricity module using power plant heat rates.

Feedstock Category	Conversion Pathway	Efficiency	Supporting Data Sources
Lipids[30]	Hydrolysis - Diesel	79%	（Holmgrenet al.， 2007）
Lipids	Hydrolysis - Jet Fuel	77%	（Holmgrenet al.， 2007）

3.7.2.2 Allocation to Conversion Pathways and final energy carriers

Users specify both primary and secondary allocation conversion pathways for each resource. Secondary allocation conversion pathways are necessary in order to allocate residual biomass resources if the primary allocation pathway has been fully satisfied (e.g., if diesel has been completely substituted with biomass-based Fisher-Tropsch diesel). The allocation of the resources to primary and secondary conversion paths is shown below in Equation 98 and Equation 99.

Equation 98

$$P.BE_{esy} = min(\sum_{b}\sum_{c}\sum_{f} AB_{fbsy} \times PE_f \times EF_{bce} \times PA_{bce}, FEC_{ey})$$

[30] The efficiency of lipids is calculated on a per ton basis. Other feedstocks are calculated on the basis of dry tons.

Equation 99

$$S.BE_{esy} = \sum_{b} max(0, \sum_{f} AB_{fbsy} \times \beta_e\ ) \times SA_{bce}$$

$$\beta_e = 1 - \frac{FEC_{ey}}{\sum_b \sum_c \sum_f AB_{fbsy} \times PE_f \times EF_{bce} \times PA_{bce}}$$

New Subscripts

e	Final energy carrier	pipeline gas, electricity, gasoline, diesel, jet fuel
b	feedstock category	cellulosic, lipid, manure, woody cellulosic
c	conversion pathway	thermal gasification, combustion, hydrolysis, pyrolysis, Fischer-Tropsch, anaerobic digestion

New Variables

$P.BE_{esy}$	Total primary allocation of bioenergy to final energy carrier e in state s in year y
$S.BE_{esy}$	Total secondary allocation of bioenergy to final energy carrier e in state s in year y
AB_{fbsy}	Available biomass for feedstock type f in feedstock category b in state s and year y
PE_f	Primary energy per dry ton for feedstock type f
EF_{bce}	Conversion efficiency from biomass primary energy to final energy carrier e from feedstock category b using conversion pathway c
PA_{bce}	Binary primary allocation variable, where a value of 1 represents selection of a pathway to final energy carrier e from feedstock category b and conversion pathway c
FEC_{ey}	Final energy consumption of final energy carrier e in year y
SA_{bce}	Binary secondary allocation variable, where a value of 1 represents selection of a pathway to final energy carrier e from feedstock category b and conversion pathway c

3.7.2.3 Emissions Intensity

The emissions intensity of delivered bioenergy (BE.EI, tons CO_2e/GJ) is calculated as a function of feedstock-specific net emissions factors (B.EI, tons CO_2e/dry ton), as shown in Equation 100. By default, these emissions factors are set to 0 for all feedstocks, but users can adjust them. A positive emissions factor would represent factors like indirect land use change that results from the development of biomass resources.

Equation 100

$$BE.EI_{esy} = \frac{\sum_b B_{besy} \times PE_f \times EF_{be} \times B.EI_b}{\sum_b B_{besy} \times PE_f \times EF_{be}}$$

New Variables

$BE.EI_{esy}$	Emissions intensity (tons CO_2e/GJ) of biomass energy delivered as final energy carrier e in state s in year y
B_{besy}	Biomass from feedstock category b allocated to final energy carrier e in state s in year y
$B.EI_b$	Biomass emissions intensity (tons CO_2e/dry ton) of feedstock category b

3.7.3 BIOENERGY COST

The delivered cost of bioenergy is composed of the cost of the biomass resource, feedstock transport costs, and conversion process costs.[31] Biomass resource costs are taken from the supply curve described in Section 3.7.1. Feedstock transport costs are shown in Table 56. No transport costs are assessed for manure or liquid feedstocks; manure is not assumed to be

[31] An additional cleaning cost specific to the injection of biomethane into the gas pipeline is also assessed for that pathway (National Renewable Energy Laboratory 2010).

transported to facilities for conversion (i.e., anaerobic digestion and biogas electricity facilities would be distributed) and we were not able to find data on lipid transport costs.

Table 56 Transport costs

Feedstock Category	Avg. Transport Cost ($/dry ton)	Supporting Data Sources
Woody Cellulosic	$26.71	（Spatially explicit projection of biofuel supply for meeting renewable fuel standard ， 2012）
Cellulosic	$9.89	（Spatially explicit projection of biofuel supply for meeting renewable fuel standard ， 2012）
Manure	$0	-
Lipids	$0	-

Feedstock process costs are assessed on a dollar per ton of feedstock basis and are derived from a variety of sources, shown in Table 57. These represent the levelized capital costs of conversion facilities, such as bio-refineries, anaerobic digesters, and gasification plants.

Table 57 Biofuel conversion costs

Feedstock Category	Conversion Pathway	Conversion Cost ($/ton)	Supporting Data Sources
All Cellulosic	Thermal Gasification - Pipeline Gas	$124	（Thermo-economic process model for thermochemical production of Synthetic Natural Gas (SNG) from lignocellulosic biomass， 2009）；（Woody biomass-based transportation fuels – A comparative techno-economic study， 2014）
All Cellulosic	Combustion - Electricity	$0[32]	-
All Cellulosic	Hydrolysis - Gasoline	$120	（Techno-economic comparison of process technologies for biochemical ethanol production from corn stover， 2010）；（Aden ， 2008）；（National Renewable Energy Laboratory， 2011）
All Cellulosic	Pyrolysis - Gasoline	$80	（Techno-economic analysis of biomass fast pyrolysis to transportation fuels， 2010）
All Cellulosic	Fischer-Tropsch - Diesel	$185	（Production of FT transportation fuels from biomass; technical options, process analysis and optimisation, and development potential， 2004）；（Large-scale gasification-based coproduction of fuels and electricity from switchgrass， 2009）；（Techno-economic analysis of biomass-to-liquids production based on gasification， 2010）
All Cellulosic	Pyrolysis - Diesel	$80	（Techno-economic analysis of biomass fast pyrolysis to transportation fuels， 2010）
All Cellulosic	Pyrolysis - Jet Fuel	$80	（Techno-economic analysis of biomass fast pyrolysis to transportation fuels， 2010）

[32] Process costs are assessed in the electricity module as the cost of the power plant.

Feedstock Category	Conversion Pathway	Conversion Cost ($/ton)	Supporting Data Sources
Manure	Anaerobic Digestion - Pipeline Gas	$40	（Krichet al.， 2005）
Lipids	Hydrolysis - Diesel	$314	（Holmgrenet al.， 2007）
Lipids	Hydrolysis - Jet Fuel	$345	（Holmgrenet al.， 2007）

The unit costs of delivered bioenergy for a final energy carrier using a given conversion pathway-feedstock category combination are calculated via Equation 101. Biomass resource costs (B.RC) are the unit price of biomass feedstocks (from the supply curve), which are feedstock category-, conversion pathway-, final energy carrier-, and year-specific. The price for each conversion pathway-feedstock category combination is based on the price of the marginal feedstock type for that combination in a given year. For instance, the price of cellulosic biomass converted through pyrolysis to jet fuel in 2030 is based on the marginal cellulosic feedstock (e.g., oat straw) in that year. Transport costs (B.TC) are feedstock category-specific, as per Table 56. Conversion costs (B.CC) are final energy carrier-, feedstock category-, and conversion pathway-specific, as per Table 57.

Equation 101

$$BE.C_{bcesy} = \frac{\left(B.RC_{bcesy} + B.TC_b + B.CC_{bce}\right) \times PE_f}{EF_{bce}}$$

New Variables

$BE.C_{bcesy}$	Bioenergy costs ($/GJ) for final energy carrier e using conversion pathway c and feedstock category b in state s in year y
$B.RC_{bcesy}$	Biomass resource costs for final energy carrier e using conversion pathway c and feedstock category b in state s in year y
$B.TC_b$	Biomass transport costs for feedstock category b
$B.CC_{bce}$	Biomass conversion costs for final energy carrier e using conversion pathway c and feedstock category b

Users can choose whether to calculate the final delivered cost of a biomass resource being allocated to a conversion pathway can be calculated on an average or marginal cost basis, as shown in Equation 102 and Equation 103, respectively.

Equation 102

$$BE.AC_{esy} = \frac{\sum_b \sum_c BE.C_{bcesy} \times B_{bcesy}}{B_{bcesy}}$$

Equation 103

$$BE.MC_{esy} = \max_{b,c} BE.C_{bcesy}$$

New Variables

$BE.AC_{esy}$	Average delivered bioenergy costs ($/GJ) for final energy carrier e in state s in year y
B_{bcesy}	Biomass from feedstock category b allocated to conversion pathway c and final energy carrier e in state s in year y
$BE.MC_{esy}$	Marginal delivered bioenergy costs ($/GJ) for final energy carrier e in state s in year y

3.7.4 DATA INPUTS AND REFERENCES

Table 58: Biomass and biofuel model inputs

Title	Units	Description	Reference
Cellulosic Process Costs	$/Ton	Conversion process costs for cellulosic biomass feedstock conversion pathways	(Gassner and Maréchal 2009); (Tunå and Hulteberg 2014); (Kazi, et al. 2010); (Aden 2008); (National Renewable Energy Laboratory 2011); (Wright, et al. 2010); (Hamelinck, et al. 2004); (Larson, Haiming and Celik 2009); (Swanson, et al. 2010)
Wood Process Costs	$/Ton	Conversion process costs for woody biomass feedstock conversion pathways	(Gassner and Maréchal 2009); (Tunå and Hulteberg 2014); (Kazi, et al. 2010); (Aden 2008); (National Renewable Energy Laboratory 2011); (Wright, et al. 2010); (Hamelinck, et al. 2004); (Larson, Haiming and Celik 2009); (Swanson, et al. 2010)

Manure Process Costs	$/Ton	Conversion process costs for manure feedstock conversion pathways	(Krich, et al. 2005)
Lipid Process Costs	$/Ton	Conversion process costs for lipid feedstock conversion pathways	(Holmgren, et al. 2007)
Transport Costs by Fuel Conversion Category	$/Ton	Transport costs for all feedstock types	(Parker 2012)
Cellulosic Process Efficiencies	GGE/Ton	Conversion process efficiencies for cellulosic biomass feedstock conversion pathways	(Gassner and Maréchal 2009); (Tunå and Hulteberg 2014); (Kazi, et al. 2010); (Aden 2008); (National Renewable Energy Laboratory 2011); (Wright, et al. 2010); (Hamelinck, et al. 2004); (Larson, Haiming and Celik 2009); (Swanson, et al. 2010)
Wood Process Efficiencies	GGE/Ton	Conversion process efficiencies for woody biomass feedstock conversion pathways	(Gassner and Maréchal 2009); (Tunå and Hulteberg 2014); (Kazi, et al. 2010); (Aden 2008); (National Renewable Energy Laboratory 2011); (Wright, et al. 2010); (Hamelinck, et al. 2004); (Larson, Haiming and Celik 2009); (Swanson, et al. 2010)
Manure Process Efficiencies	GGE/Ton	Conversion process efficiencies for manure feedstock conversion pathways	(Krich, et al. 2005)
Lipid Process Efficiencies	GGE/Ton	Conversion process efficiencies for lipid feedstock	(Holmgren, et al. 2007)

		conversion pathways	
Secondary Resource Cumulative Supply	Tons	Secondary resource biomass supply, by commodity price point, in 2013 and 2030	(Oak Ridge National Laboratory 2011)
Forest Residue Resource Cumulative Supply	Tons	Forest residue resource biomass supply, by commodity price point, in 2013 and 2030	(Oak Ridge National Laboratory 2011)
Primary Agriculture Resource Cumulative Supply	Tons	Primary agriculture resource biomass supply, by commodity price point, in 2013 and 2030	(Oak Ridge National Laboratory 2011)
Currently Used Resource Cumulative Supply	Tons	Currently used resource biomass supply, by commodity price point, in 2013 and 2030	(Oak Ridge National Laboratory 2011)

Aden, A. Biochemical Production of Ethanol from Corn Stover : 2007 State of Technology Model. Technical Report, Golden, Colorado: National Renewable Energy Laboratory, 2008.

Gassner, Martin, and François Maréchal. "Thermo-economic process model for thermochemical production of Synthetic Natural Gas (SNG) from lignocellulosic biomass." Biomass and Bioenergy, 2009: 1587-1604.

Hamelinck, Carlo N., André P.C. Faaij, Herman d. Uil, and Harold Boerrigter. "Production of FT transportation fuels from biomass; technical options, process analysis and optimisation, and development potential." Energy, 2004: 1743-1771.

Holmgren, J., C. Gosling, T. Marker, G. Faraci, and C. Perego. "New developments in renewable." Hydrocarbon Processing, September 5, 2007.

Kazi, Feroz K., et al. "Techno-economic comparison of process technologies for biochemical ethanol production from corn stover." Fuel, 2010: S20-S28.

Krich, Ken, Don Augenstein, J.P. Batmale, and John, Rutledge, Brad, Salour, Dara Benemann. "Biomethane from Dairy Waste." 2005.

Larson, Eric D., Jin Haiming, and Fuat E. Celik. "Large-scale gasification-based coproduction of fuels and electricity from switchgrass." Biofuels, Bioproducts, and Biorefining, 2009: 174-194.

National Renewable Energy Laboratory. October 18, 2010. http://www.nrel.gov/docs/fy11osti/49629.pdf.

National Renewable Energy Laboratory. "Process Design and Economics for Conversion of Lignocellulosic Biomass to Ethanol Thermochemical Pathway by Indirect Gasification and Mixed Alcohol Synthesis." Technical Report, Golden, Colorado, 2011.

Oak Ridge National Laboratory. Billion Tons Study Update. U.S. Department of energy, 2011.

Parker, Nathan. "Spatially explicit projection of biofuel supply for meeting renewable fuel standard." Transportation Research Record: Journal of the Transportation Research Board, 2012: 72-79.

Swanson, Ryan M., Alexandru Platon, Justinus A. Satrio, and Robert C. Brown. "Techno-economic analysis of biomass-to-liquids production based on gasification." Fuel, 2010: S11-S19.

Tunå, Per, and Christian Hulteberg. "Woody biomass-based transportation fuels – A comparative techno-economic study." Fuel, 2014: 1020-1026.

Wright, Mark M., Daren E. Daugaard, Justinus A. Satrio, and Robert C. Brown. "Techno-economic analysis of biomass fast pyrolysis to transportation fuels." Fuel, 2010: S2–S10.

4 Non-Energy, Non-CO_2 Greenhouse Gases

PATHWAYS' Non-Energy/Non-CO_2 Module, called the NON module for the rest of this document, is used to project emissions from sources not related to energy conversion, e.g. chemically created CO_2 from cement manufacturing, and sources of Non-CO_2 greenhouse gases, e.g. landfill methane. Regardless of gas, all emissions are tracked using CO_2 equivalent (CO_2eq) units, according to conversion and reporting guidelines for CARB's emissions inventory, which follows IPCC conventions.

NON categories are listed in Table 59, along with their tracked emissions and the method used to forecast their baseline emissions. Different categories in the NON module employ different forecasting techniques. Mean and linear fit forecast methods rely on extrapolation from historical emissions data and F-gas forecasts are based on an external model of fugitive emissions developed by CARB (see Sections 4.1.1 and 4.1.2 for details).

Table 59. NON Module emission categories and their primary emissions

Category	Emissions	Forecast method
Cement	CO_2 chemically released during production	Mean
Waste	Biogenic methane from landfills and waste water	Mean
Petroleum Refining	Fugitive methane	Linear fit
Oil Extraction Fugitive Emissions	Fugitive methane	Linear fit
Electricity Gen. Fugitive and Process Emissions	Fugitive methane and CO_2	Linear fit
Pipeline Fugitive Emissions	Fugitive methane	Linear fit
Agriculture: Enteric	Biogenic livestock methane from digestion	Mean
Agriculture: Soil Emissions	N_2O from fertilized soils	Linear fit
Agriculture: Manure	Methane from decaying manure	Mean
Agriculture: Other	Biomass burning CO_2 and rice methane	Linear fit
Fgas: RES	Fugitive refrigerants: CFCs, HCFCs, and HFCs	CARB forecast
Fgas: COM	Fugitive refrigerants: CFCs, HCFCs, and HFCs	CARB forecast
Fgas: IND	Fugitive refrigerants: CFCs, HCFCs, and HFCs	CARB forecast
Fgas: LDV	Fugitive refrigerants: CFCs, HCFCs, and HFCs	CARB forecast
Fgas: HDV	Fugitive refrigerants: CFCs, HCFCs, and HFCs	CARB forecast
Fgas: Other trans	Fugitive refrigerants: CFCs, HCFCs, and HFCs	CARB forecast
Fgas: Electricity	Primarily fugitive SF_6 from electrical equipment	CARB forecast
Land: Fire	primarily CO_2, but not well quantified	Not included
Land: Use change	primarily CO_2, but not well quantified	Not included

CARB's official emissions inventory from 8/1/2013 in IPCC categories is the primary source of historical emissions data.

Table 11 details how NON Module categories are mapped to CARB inventory categories. As explained in the emissions forecast section of this document, Fgas and land use categories do not rely on historical data and are therefore not addressed in the table.

Table 60. Sources for historical NON Module emissions data. All are based on the CARB inventory released 08/01/2013 with historical data spanning 2000-2011.

Category	Historical data source (2000-2011)
Agriculture: Enteric	IPCC Level 1: Agriculture, etc. & IPCC Level 3 - 3A1 - Enteric Fermentation
Agriculture: Manure	IPCC Level 1: Agriculture, etc. & IPCC Level 3: 3A2 - Manure Management
Agriculture: Soil	IPCC Level 1: Agriculture, etc. & IPCC Level 3: 3C2 - Liming, 3C4 - Direct N2O Emissions, 3C5 - Indirect N2O Emissions
Agriculture: Other	IPCC Level 1: Agriculture, etc. & IPCC Level 3: 3C1 - Emissions from Biomass Burning, 3C7 - Rice Cultivations
Cement	IPCC Level 1: Industrial & IPCC Level 3: 2A1 - Cement Production
Waste	IPCC Level 1: Waste
Petroleum Refining	IPCC Level 1: Energy and IPCC Level II Fugitive and Sector: Petroleum Refining
Oil & Gas Extraction	IPCC Level 1: Energy and IPCC Level II Fugitive and Sector: Oil Extraction
Electricity Fugitive Emissions	IPCC Level 1: Energy and IPCC Level 2: 1B - Fugitive and all 'Sector and Activity Details' related to electricity generation including CHP
Pipeline Fugitive Emissions	IPCC Level 1: Energy and IPCC Level II Fugitive and Sector: Pipelines Natural Gas

The rest of this section describes methods for forecasting reference CO_2eq emissions (Section 4.1), defining and implementing mitigation measures (Section 4.2) in the NON Module. Section 4.4 discusses the issues and assumptions that shaped the primary mitigation scenario adopted for the PATHWAYS study.

4.1 Reference Emissions Forecast

Different categories on NON Module emissions feature different methods for establishing reference forecasts out to 2050. Forecasting methods in the NON Module include extrapolation from historical data and importing forecasts from external models. In the case of land and fire emissions, no forecasts were made. Figure 10 provides a visualization of the NON Module reference case forecast emissions, and the remainder of this sub-section explains the methods used to produce this forecast.

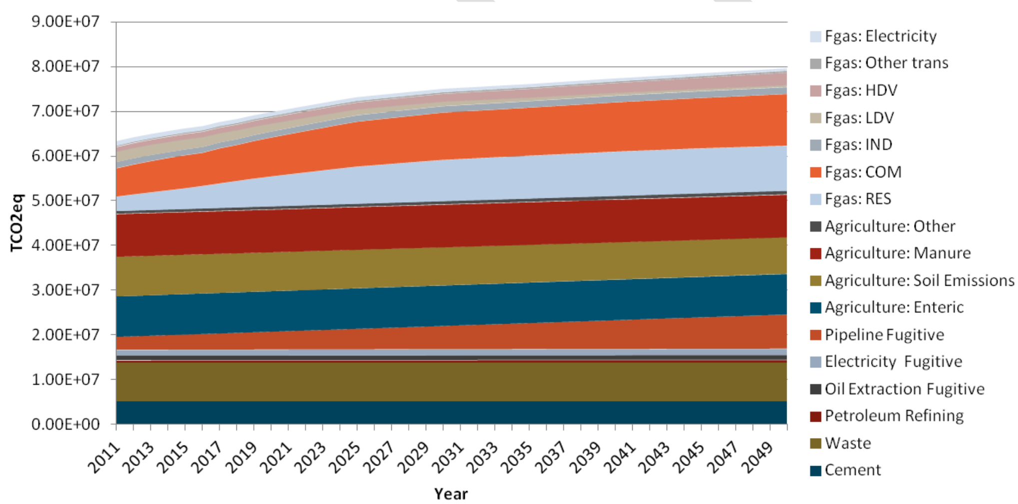


Figure 22: Reference case NON Module emissions by category

4.1.1 FORECASTS USING HISTORICAL DATA

Forecasts for the agricultural categories, fugitive methane from electricity generation, pipelines, oil and gas, and refining, methane from waste, and CO_2 from cement are all based on extrapolation from CARB inventory historical data spanning 2000-2011. As the third column in Table 59 suggests, some of these forecasts are based on predictions from linear regression fits of the data and some are based on the mean of the historical data. Linear fits are used by default, but the short duration of available historical data allowed outlier data to produce implausible forecasts with emissions heating to zero (cement) or increasing dramatically without underlying causes (waste, agriculture). In these cases, the forecasts are based on the mean of the historical data.

4.1.2 FORECASTS USING AN EXTERNAL MODEL

Baseline emissions trajectories for F-gas categories are the same as those used in the CALGAPS model developed at LBNL by Staff Scientist Jeff Greenblatt[33]. The CALGAPS trajectories are, in turn, based on an equipment stock-based F-gas inventory model developed at CARB by Glenn Gallagher[34][35]. Gallagher's model is designed to track the inventory of various F-gases (mostly refrigerants) in service in various equipment types (car and building AC units, residential and commercial refrigerators, etc.). The key observation is that F-gases leak out of

[33] Greenblatt, Jeffery B. 2015. "Modeling California Policy Impacts on Greenhouse Gas Emissions." Energy Policy 78 (March): 158–72. doi:10.1016/j.enpol.2014.12.024.
[34] Gallagher, Glenn, Tao Zhan, Ying-Kuang Hsu, Pamela Gupta, James Pederson, Bart Croes, Donald R. Blake, et al. 2014. "High-Global Warming Potential F-Gas Emissions in California: Comparison of Ambient-Based versus Inventory-Based Emission Estimates, and Implications of Refined Estimates." Environmental Science & Technology 48 (2): 1084–93. doi:10.1021/es403447v.
[35] Both Greenblatt and Gallagher served as advisors on the implementation of the NON Module.

equipment to become fugitive emissions during their normal operating lives. These emissions happen at different rates for different types of equipment, with the leakiest connections belonging to commercial refrigeration and car AC units and the biggest charges of gas belonging to commercial refrigeration. There are also emissions associated with final disposal at the end of equipment life, especially refrigerators and AC units. Given charge sizes and leakage factors, combined operational and end of life total emissions (in volume of gas) can be calculated each year for the whole stock of each equipment type. Determining the composition, and therefore the average GWP, of the leaking gases is the other half of the calculation.

The gases used vary by type and vintage of equipment, so the CARB model tracks the number of each vintage of equipment in use over time, with assumptions about lifetimes determining the retirement rate of older equipment. The effective GWP of F-gases in use (and therefore leaked) is the weighted average of the GWP of all the individual pieces of equipment, and therefore changes from year to year.

Policy drivers are the primary reason the compositions have changed. Until the early 1990s, when the Montreal Protocol took hold, the F-gases used as refrigerants were CFCs, some of the most potent ozone depleting substances. Gradually CFCs have been replaced with HCFCs and HFCs, which do not significantly deplete ozone, but turn out to be very potent greenhouse gases. Now, the potent greenhouse gases are starting to be replaced by gases with lower GWP. The reference forecast is based on estimated F-gas deployment from carrying out existing state and federal regulations (i.e. eventual elimination of CFCs and modest declines in the use of potent GWP gases).

4.1.3 LAND USE/LAND CHANGE

Land: Use and **Land: Fire** categories of NON Module emissions became a special cases in this analysis. These categories are notoriously hard to measure and predict, are not included in official state emissions inventory data, and are not classified as energy-related emissions (the focus of PATHWAYS). However, they are known to be the source of significant uncertainties in overall emissions estimates (under some conditions it is not even known if they are net emitters or sinks). At the same time, some promising and policy-relevant land use and fire management strategies have been proposed. There are also state-sponsored studies underway, such as the Forest Carbon Plan (expected in 2016) that may clarify emissions and mitigation options for these categories. To support sensitivity analysis and future inclusion of improved data and mitigation options, the NON Module allows users to enter their own exogenous reference forecasts for emissions in the Land: Use and Land: Fire categories and allows the subsequent specification of mitigation measures that reduce those emissions. However, the values for all of these are defaulted to zero, with no impact on overall outcomes.

4.1.4 HEAT PUMP FUGITIVE EMISSIONS

Because aggressive mitigation scenarios deploy very large numbers of heat pumps, it is reasonable to wonder if their additional fugitive emissions are a significant future source of Non-Energy emissions. We performed a calculation using stock data from the rest of the PATHWAYS sectors to address this question. CARB F-gas forecast equipment attribute data for equipment types similar to heat pumps was used to estimate what the charge volume, annual leakage, end of life leakage, and stock averaged GWP would be for space heating and hot water heat pumps in residential and commercial buildings. Heat pump stock count and lifetime data from RES and COM PATHWAYS sectors was used to estimate annual total emissions from leakage and end of life from heat pumps introduced by mitigation measures. The calculation yielded an estimate of approximately 0.5-0.75 $MMTCO_2eq$ in 2050 additional to a reference case of approximately 27 $MMTCO_2eq$ from all F-gas sources, which is about 2-3%. This is a small difference that did not justify the modeling complexity of tracking heat pump stocks and calculating their emissions dynamically. Further, with the assumption that heat pumps (as key mitigation technologies) will be designed with mitigation in mind, we can assume well-sealed closed loop systems, best practice end of life disposal, and accelerated transitions to low GWP working fluids. Under these assumptions, additional emissions are not large enough to significantly impact model results. However, those key heat pump features will need to be required by fuel switching policies to manifest in the market.

4.2 Mitigation measures

NON Module emission measures consist of several attributes, which are detailed in Table 14.

Table 61: Attributes of NON Module emission measures

Attribute	Description
Category	The category of emissions the measure applies to
Impact	The fraction of emissions the measure eliminates by the saturation year and after
Start Year	The first year of measure impact
Saturation Year	The year the measure reaches its full potential
Levelized Cost	The levelized cost of the measure implementation in $/TCO2eq

Between the start year and the saturation year, measure impacts follow a linear ramp, achieving the full impact fraction by the saturation year.

Equation 104: The fraction of emission reduced per year

$$FEI_{jmy} = max\left(min\left(\frac{y_{sat} - y}{y_{sat} - y_{start}}, 1\right), 0\right) \times ECI_{jm}$$

New Variables

FEI_{jmy}	fraction of emissions impacted per measure m per emission category j in year y
y_{sat}	saturation year
y_{start}	measure start year
ECI_{jm}	fractional emission change (aka Impact) per measure m per emission category j

Note that the saturation calculation is forced by the *max* and *min* functions to fall within limits of 0 and 1, representing the period prior to implementation and the period after complete saturation, respectively.

4.3 Emissions Calculations

Equation 105: Emissions change

$$EC_{jmy} = FEI_{jmy} \times RE_{jy}$$

New Variables

EC_{jmy}	emission change per measure m per emission category j in year y
RE_{jmey}	reference case emissions for category j in year y

Measure costs are already expressed in levelized \$/TCO_2eq, so mitigation cost calculations are a simple multiplication.

Equation 106: Costs

$$N.AMC_y = \sum_j \sum_m EC_{jmy} \times LC_m$$

New Variables

$N.AMC_{ey}$	annualized measure costs in year y
LC_m	levelized costs for measure m

Because emissions in TCO_2eq are tracked directly in the NON Module, sector total emissions are simply calculated as the sum across all categories of emission after mitigation measures have been applied.

Equation 107: Final emissions

$$N.CO2_y = \sum_j \sum_m (RE_{jy} - EC_{jmy})$$

New Variables

$N.CO2_y$	NON Module total emissions (TCO_2eq) in year y

4.4 Scenario Mitigation Discussion

The bookkeeping and calculations for the NON Module are all fairly straight forward. The primary source of complexity is the diversity in emission categories and the supporting literature and expert opinion on what levels of mitigation are possible. Table 62 provides the NON Module mitigation measures for the Straight Line Scenario. The remainder of this appendix discusses the assumptions, ideas and inputs that shaped the impact numbers used.

Table 62: Straight line scenario mitigation measures

Category	Description	Reduction by 2050
Cement	Fly ash and other substitutes	0.2
Waste	80% reduction at 80% penetration	(0.8*0.8)
Petroleum Refining	80% decline with 50% leakage reduction	0.9
Oil Extraction Fugitive Emissions	80% decline with 50% leakage reduction	0.9
Electricity Generation Fugitive and Process Emissions	80% decline with 50% leakage reduction	0.9

Category	Description	Reduction by 2050
Pipeline Fugitive Emissions	80% decline with 50% leakage reduction	0.9
Agriculture: Enteric	Summary of non-energy mitigation	0
Agriculture: Soil Emissions	Summary of non-energy mitigation	(0.45+0.07)
Agriculture: Manure	Side calculation in Manure Emissions v3	0.62
Agriculture: Other	Rice and crop residue burning	0.5
Fgas: RES	Max global effort	0.8
Fgas: COM	Max global effort	0.8
Fgas: IND	Max global effort	0.8
Fgas: LDV	Max global effort	0.8
Fgas: HDV	Max global effort	0.8
Fgas: Other trans	Max global effort	0.8
Fgas: Electricity	Max global effort	0.8
Land: Fire	N/A	0
Land: Use change	N/A	0

Costs: Cost data on mitigation options for non-energy, non-CO2 emissions is limited. The ranges estimated here can be broadly categorized as “low-cost” measures represented with costs of $10/ton, “medium cost” measures represented with cost of $50/ton and “high cost” measures represented with costs of $100/ton. These costs remain highly uncertain and represent an area where further research is needed.

Cement: Cement manufacturing produces CO_2 chemically. There have been some proposals for new chemistries that could possibly address these emissions directly, but we are not aware of any proposal for a scalable solution of this type. Thus the main options include fillers and concrete blends that dilute the cement content. The potential for mitigation from these options is limited.

Waste: The most aggressive numbers here assume 80% capture efficiency in 80% of locations. Landfill emissions represent a large fraction of these emissions and the USEPA LFG calculator (http://www.epa.gov/methane/lmop/projects-candidates/lfge-calculator.html) places the range of capture efficiencies at 60-90% for landfills. Further, CalRecycle currently has legislation in place to recycle, compost, or avoid 75% of total waste generated by 2020. The terminology has changed from their previous goal for diverting waste from landfill, in that it no longer accepts thermal treatments, landfill daily cover etc. In the end, these numbers are rough estimates.

Fossil infrastructure: In the PATHWAYS model, the aggressive deployment of low carbon electricity generation, transportation fuels, and pipeline gas dramatically reduces demand for fossil fuels. The NON Module mitigation measures reflect an 80% decline in fugitive emissions from fossil fuel related activities (extraction, refining, pipeline transport, generation) coupled with efforts to find and fix 50% of leak volume.

Agriculture - Soil: Soil emissions are primarily natural and fertilizer-driven N_2O, followed by methane from decomposition, and CO_2 from burning. Reductions assumed in the most aggressive case come from fertigation, which is sub-surface fertilizer application to reduce total fertilizer requirements and prevent runoff, is known to reduce runoff by ~20-60%. The model assumes that translates into reduced emissions of ~45%. On top of those, conservation tillage is assumed to provide a further ~7% reduction.

Agriculture - Enteric: Some studies claim that livestock can be bred of fed to reduce digestive methane emissions, but there are compelling biological and practical reasons to be skeptical of these potentials. The most believable mitigation strategy for livestock would come from changing consumer eating habits towards more plants and vegetables, but this was considered outside the scope of PATHWAYS, whose goal is to preserve existing levels of services in all sectors, including food. No emissions improvements were assumed here.

Agriculture - Manure: This estimate was based on a side calculation (reproduced below) to determine the fraction of manure accessible for anerobic digestions. Manure spread across a field is inaccessible for digestion for all intents and purposes, so is excluded from the calculation below.

An Assessment of Biomass Resource in California, 2012 DRAFT

	Dairy cows - lactating & dry	Computed to check
Num in CA	1,779,710	
lb wet manure / animal-day	140	
moisture (mass)	87%	
lb dry manure / animal-day	18.7	18.2
lb dry manure / animal-y	6,807	6,643
Statewide (BDT/y)	6,057,465	5,911,307
Technical avail. Factor	0.5	

	BDT/y in CA
Dairy manure (total production)	6,057,465
Dairy manure (technical availability)	3,028,733

From ARB 2014 inventory update, Annex 3B, manure management (dairy cows only, leaving out a few minor sources)

			Calculated	
Management system	**% of dairy cows**	**Tg CO_2e**	**BDT Manure**	**Mg CO_2e/BDT**
Anaerobic digester	1%	0.04	72,084	0.6
Anaerobic lagoon	58%	8.71	3,513,330	2.5
Liquid/slurry	20%	1.35	1,211,493	1.1
Daily spread	11%	0.01	642,091	0.0
Pasture	1%	0.00	40,658	0.0
Solid storage	9%	0.07	551,229	0.1
Total	100%	10.2	6,030,885	

Average avoided emission factor	2.1	**Mg CO_2e/BDT**
Maximum manure w/avoidable CH_4	3,028,733	**BDT/y**
Maximum avoidable manure CH_4	6,448,718	**Mg CO_2e/y**

2010 Manure emissions	10,432,779	**Mg CO_2e/y**
Percentage reduction	62%	

Agriculture - Other: The emissions from burning crop residues and from rice methane were assumed to be reducible by about 50% via management practices or different crop selection.

F-gases: SNAP is the Significant New Alternatives Policy Program that the US EPA started in the 1990s to list acceptable and unacceptable substitutes to ozone-depleting substances, i.e. for Montreal Protocol compliance. They have recently expanded the program to also address high-GWP HFCs. The entire proposed SNAP rule to reduce HFC usage, is on the web at: http://www.epa.gov/spdpublc/snap/index.html then click on the recent additions **"**EPA publishes proposal to prohibit certain high-GWP HFCs as alternatives under SNAP**"** (8/6/14).

If adopted, the SNAP proposal will create additional HFC GHG reductions above BAU, but cannot achieve the 80% HFC reduction goal in new equipment/uses because it does not include air-conditioning, and still allows HFCs with GWPs as great as 2600 (such as the HFC blend R-421A) for use in supermarket refrigeration. It does knock out R-404A and R-507, with GWPs of 3922 and 3985 (IPCC AR4 GWP values).

In theory, California could adopt these expanded SNAP rules if the EPA does not put them into practice and in theory CA could address the remaining high GWP uses that SNAP avoids. Alternately, California could also theoretically adopt the European Union F-gas regulations model that begins 2016. However, a single state is unlikely to be able to change the market for all relevant products, so the actual impact would be diminished by incomplete compliance and out of state imports.

The best global effort, required to avoid emissions from products originating out of state and out of country, would likely take the form of updates to the Montreal Protocol that could adopt an aggressive HFC phase-down similar to the European Union, but this would be unlikely to come into force until 2020.

Finally, there are many specialty uses of F-gases that might not effectively come under the adopted protocol. The most aggressive scenario, which assumes maximum *global* effort, estimates an 80% reduction in F-gas emissions by 2050, assuming that stringent global requirements come into force by 2020, giving 30 years for most older technologies to retire, and allowing for some ongoing emissions in specialty uses.

4.5 Model Input Variables

Table 63: Non-energy, non-CO2 model inputs

Variable	Title	Units	Description
CALGAPS_baseline	CALGAPS baseline	MTCO2e	Baseline emissions trajectories used in the CALGAPS model and provided by Jeff Greenblatt in spread sheet form, based on modeling results from CARB's "Methodology to Estimate GHG Emissions from ODS Substitutes" from 2013

Variable	Title	Units	Description
Data_NON_Ele	Data:NON Ele	Tons CO2e	Subsector GHG emissions data from CARB's emissions inventory by IPCC category: CA_ghg_inventory_by_ipcc_00-11_2013-08-01.xlsx Agriculture: (IPCC Level I Agriculture) Cement: Clinker production Waste: (IPCC Level I Waste) Petroleum Refining: (IPCC Level I Energy/IPCC Level II Fugitive/Sector:Petroleum Refining) Industrial: (IPCC Level I Industrial)-Cement Oil & gas Extraction: (IPCC Level I Energy/IPCC Level II Fugitive/Sector:Oil Extraction) Electricity Fugitive Emissions: (IPCC Level I Energy/IPCC Level II Fugitive/Sector:Anything related to electricity generation including CHP) Pipeline Fugitive Emissions: (IPCC Level I Energy/IPCC Level II Fugitive/Sector:Pipelines Natural Gas)

Variable	Title	Units	Description
Data_NON_Ele1	Data:NON2 Ele	MTCO2e	Subsector GHG emissions data from CARB's emissions inventory by IPCC category: CA_ghg_inventory_by_ipcc_00-11_2013-08-01.xlsx Agriculture: (IPCC Level I Agriculture) Enteric: Level 3 - 3A1 - Enteric Fermentation Manure: Level 3 - 3A2 - Manure Management Soil Emissions: 3C2 - Liming, 3C4 - Direct N2O Emissions, 3C5 - Indirect N2O Emissions Other: Level 3 - 3C1 - Emissions from Biomass Burning, 3C7 - Rice Cultivations Cement: Clinker production Waste: (IPCC Level I Waste) Petroleum Refining: (IPCC Level I Energy/IPCC Level II Fugitive/Sector:Petroleum Refining) Industrial: (IPCC Level I Industrial)-Cement Oil & gas Extraction: (IPCC Level I Energy/IPCC Level II Fugitive/Sector:Oil Extraction) Electricity Fugitive Emissions: (IPCC Level I Energy/IPCC Level II Fugitive/Sector:Anything related to electricity generation including CHP) Pipeline Fugitive Emissions: (IPCC Level I Energy/IPCC Level II Fugitive/Sector:Pipelines Natural Gas)

Variable	Title	Units	Description
Data_NON_Land	Data:NON Land	MTCO2e	All zeros placeholder that can be populated with non-zero values from exogenous sources as needed. The values should be in MTCO2e.

4.6 Non-Energy Mitigation Potential

This appendix contains an unedited summary and discussion of California non-energy mitigation potential provided by LBNL. The potentials outlined are not those used in the official scenarios. Rather than supporting specific scenarios, this appendix should be considered valuable background reading for anyone interested in non-energy mitigation potential and the type of information that informed the reference trajectories and mitigation scenarios.

Summary of non-energy mitigation research for California

Dr. Sally Donovan, Environmental Consultant, Victoria, Australia

Transmitted to E3 by Jeffery Greenblatt, Lawrence Berkeley National Laboratory

30 December 2014

4.6.1 F-GASES

4.6.1.1 Large commercial refrigeration

The main sources of emissions in this sector are leakage during operation, which are typically up to 30% of the full charge per year (ICF, 2011)i. (They are generally topped up to ensure continued maintenance of appropriate temperatures).

Better management of leaks can be achieved by requiring leakage detection equipment be included with larger appliances, or requiring leakage checks be carried out periodically for medium sized equipment. In both of these cases, repair of leaks would be required to be performed within a short period of detection. It is estimated that this measure could reduce annual leakage rates to 18% (ICF, 2011) at a cost of $4-7 per tonne of CO2 savedii.

In California there are already some legislative drivers that aim to reduce leakage from refrigeration equipment. The Refrigerant Management Program (RMP) (CARB, 2014) requires any single piece of refrigeration equipment with more than 50 pounds of charge to comply with annual leakage monitoring and reporting requirements. The mitigation option here would build on this by requiring automated leakage detection equipment and more frequent reporting, especially in larger refrigeration equipment.

Other mitigation measures include improving the quality of equipment. For example leaks most commonly occur around flare joints and shaft seals. Flare joints occur where two pieces of pipe are joined together and can be minimized by sourcing longer pipes. Secondary shaft seals are now widely available. These have a second seal that can work when the primary seal becomes damaged, and maintain equipment until the primary seal is repaired. (An alarm is activated when the primary seal fails, so operators know a repair needs to be performed.) There was little info available on the effectiveness of these options, and mostly it seems other options are being chosen in favour of this so no data presented in the final summary. It is in the interests of owners to purchase higher quality equipment, as leaks will lead to equipment failures and end up being more costly. Therefore no intervention is suggested in relation to this.

The final mitigation measure is to use low-GWP refrigerants. There is a lot of new development around these, particularly CO_2 and ammonia in large scale equipment. The aim of low GWP equipment is to provide equivalent or better energy efficiency so that emissions due to refrigerant leaks will become negligible. The cost of changing over to low GWP equipment is estimated to be $25-30 per tonne CO2 saved[ii], however in time as the technology because more widespread these costs are expected to become negligible.

There are also some voluntary schemes in place targeting specific sectors: GreenChill program[iii] operated by the USEPA, targets supermarkets, while LEED program[iv] by the Green Building Council targets new buildings. Both schemes operate a certification scheme, where businesses can earn certification of different levels depending on the mitigation of refrigerants in their buildings. Certification can be obtained by either minimizing leaks or using low GWP refrigerants. Businesses can then advertise their certification to consumers.

End-of-life management has potential to release about 10% of charge. Decommissioning usually takes place on-site so there are no transport/handling emissions to consider. Three options exist: Recyclingv, where the refrigerant is removed and used to top another piece of equipment. This practise is only permitted within the same company. It cannot be removed and sold to another company. Reclamation involves removing the refrigerant and selling to a registered refrigerant reclamation company (must be approved by the USEPA). The company than cleans the refrigerant to comply with ARI 700 and can then sell it on. This process seems relatively unpopular due to lack of certified reclaimers. The majority of reclaimed refrigerant tends to be HCFCs and other ozone depleting substances that have reduced production levels. The final option, destruction, seems more practical in most cases. This can reduce emissions from 10% to 5%.i

4.6.1.2 Large commercial A/C

Basically the same as refrigeration in terms of mitigation options.

4.6.1.3 Small commercial/residential refrigeration and A/C

Leaks during operation are relatively small in these cases, and they have a small charge size. The biggest potential for emissions occurs during end-of-life management. Typically the most leaks occur during transport and handling as these are often collected as part of general household waste collection services, rather than certified refrigerant handlers. Emissions can be up to 100%i ii.

In California the Department of Toxic Substances Control operates a certified appliance recycling (CAR) programvi which covers refrigerants. Although recyclers that only work with refrigerants do not need CAR certification is they already have certification from the USEPA. Transports, deliverers are not required to have CAR certification.

The USEPA Responsible Appliance Disposalvii program also pertains to residential products. For example Southern California Edison offers refrigerator disposal to its customers, with free collection and a $35 incentive to upgrade to a more efficient appliance.

Use of low GWP refrigerants is probably the most feasible option, and USEPA has added HC refrigerant based refrigerators to their SNAP listviii. The USEPA are also slowly phasing out high GWP refrigerants by removing them from SNAP lists. It is unlikely that any further intervention would be worth the costs.

4.6.1.4 Others

In general changing appliances to those with low GWP refrigerants will be the most effective way of mitigating emissions. As stated above the USEPA has already began to phase out high GWP refrigerants through their SNAP lists, so it is not likely that further intervention into this process would be worthwhile.

4.6.1.5 Foam from appliances

Emissions occur at three life cycle stages: manufacturing, operation and end-of-life. For manufacturing emissions can be up to 14% ix. One mitigation option, capturing the gas for reuse, was considered but very little data exist on this method and it doesn't seem to be widely practised. In other regions, such as Europe, they have opted to use either a low GWP gas or an alternative form of insulation such as vacuum insulation panels. During operation emissions are very small, around 1%ii ix, and there are no mitigation possibilities.

Emissions during decommission and handling can be up to 80%ii. The majority of foams are landfilled either directly, or after shredding. This means 100% of the gas could potentially be emitted over time. Destruction of foams can significantly reduce these emissionsii. Destruction costs are estimated to be $88-$115 per appliance ix depending on the process, which can be manual, semi-automated or fully automated. There are 35 foam recovery plants in the US, only one of which is fully automated. vii The cost of new foam recovery plant is estimated as $520,000ix. The USEPA's RAD program also includes destruction of foams and the associated gases when appliances are disposed ofvii. The CAR vi program on the other hand does not require destruction of foams and their gases, it only covers the refrigerant.

4.6.1.6 Foam from building insulation

The mitigation of foam for building insulation is very similar to that for appliances. Alternative forms of insulation that can be used in buildings include fibreglass and mineral wool.

The destruction of building foams is estimated to cost around $300 per kg. ix Most of the destruction facilities described above were developed for appliances, but at least one in California has the ability to take foams as well.

4.6.2 WASTE

4.6.2.1 New and existing landfills

New landfills and existing landfills that did not incorporate a gas collection system into their design can be mitigated in several ways depending on their age and gas flow rate. For new or more recent landfills that still have a high gas flow rate (100 /hour) the landfill could be retrofitted with a gas collection system. The collected gas can either be converted to electricity or used directly for heating. The first option will reduce emissions by 60-90%, plus there will be an offset from electricity production estimated to be 0.043kWh per cu. ft. of landfill gasx. The cost of retrofitting this will be $5.15million initially and then $526 per year in operating costs[x]. The second option will also reduce emissions by 60-90%, and offset around 506 Btu per cu. ft. landfill gas[x]. The cost of setting up this type of gas collection system is estimated to be $2.7 million, although will depend on the distance from the landfill to the place where the gas will be used. Laying pipes will be a portion of the costs. The yearly operating costs will then be $112[x].

The USEPA currently offers voluntary assistance to landfill owners and operators to incorporate gas collection systems through their landfill methane outreach programxi.

For older landfills with a low gas flow rate aeration techniques could be a good way to increase the rate of waste decomposition, and to convert the gas from methane to CO_2, before it is emitted to the atmosphere. This technique can reduce emissions by 30-60% at a cost of $1-$6 per tonnexii.

4.6.2.2 Composting

The methane from landfills is caused by the degradation of biological components of the waste stream, such as food and garden waste. Composting these wastes can produce a product high in nutrients required for plant growth. This can reduce the need for synthetic fertilizers, as well as removing the waste from landfills. Therefore there are many benefits to segregating the compostable components of the waste stream for separate treatment.

There are different types of composting. The choice will depend on the amount of waste being processed, and the proximity of the composting site to residential properties. Small, low tech composting will cost around $30-60 per tonne of wastexiii; open windrow or covered static piles costs between $50-60 per tonnexiii; more advanced processes such as aerated covers, covered bays, small scale vessel cost $60-110 per tonne, plus have a start-up costs of $150,000 to $1 millionxiii. These more expensive processes can process more waste, and also significantly reduce the risk of odor nuisance, so can be located closer to residential properties.

California has had segregated collections for food and garden waste for around ten years, so the process should be well established.xiv At the moment the aim of the program is to ensure all collected waste is genuinely recycled, i.e. composted materials are no longer to be used as daily cover for landfills, excess waste cannot be sent to waste to energy plantsxv. The biggest scope for further mitigation is to ensure the quality of the composted waste, so that it can be applied to soils as a fertilizer, and to maximize public participation.

4.6.2.3 Anaerobic Digestion

Anaerobic digestion (AD) is the other main option for biologically treating waste. The practise is less well established, and poorly understood compared to composting. The potential advantage of AD is that gas can be collected for energy production. However, it is highly unstable, and food waste can only make up a relatively small proportion of the overall feed going into the process. One example a plant with a 120,000 tonnes per year capacity, producing 6MW electricity cost $40 million.xvi

4.6.2.4 Waste Prevention

The most effective way to reduce emissions from waste is to minimize the amount generated. Food waste is a key component of this as it is one of the major causes of emissions from landfills. A UK based study found that only 19% of food waste was unavoidable components such as vegetable peelings. The remaining 81 % was ediblexvii. After this study which took place in 2007, the UK government invested $100 million per year into a set of food waste prevention programs. After 5 years the amount of avoidable food waste was reduced by 21%, saving 4.4 million tonnes of CO_2. xviii The initiative also saves families money, by reducing the amount of food that is purchased and thrown away without being eaten. The program involved working with supermarkets to promote better food management in the home, by providing consumers with better explanations of appropriate food storage, as well as expiration and use by dates. Supermarkets also participate by no longer offering multi-buy offers on perishable foods, and offering a broader range of packaging sizes to cater to different sized households. The reduced food purchases were also estimated to have saved the average UK household $130.

In the US there are two voluntary schemes that encourage consumers to reduce their food waste: The Food Waste Challenge organized by the USDA; and the USEPA's Food Recovery Challenge.xix Both schemes aim to improve consumer purchasing habits when it comes to food, and also to encourage better management of unwanted food, i.e. donating to a food bank, feeding scraps to animals etc.

Other waste streams were considered, such as paper, but food was the most relevant to mitigating greenhouse gases.

4.6.3 AGRICULTURE

4.6.3.1 Enteric fermentation

Much research exists into reducing emissions from livestock due to enteric fermentation. However, the majority of these are still theoretical, or in early stages of experimentation, so are not considered feasible for this study.

4.6.3.2 Manure management

Manure is the biggest source of greenhouse gas emissions from agriculture, along with enteric fermentation. The choice of option will depend on the current method of disposal. The simplest approach is to use lagoon covers. Particularly if the current method of manure management involves hosing into a lagoon.

Covering a lagoon with straw that has been treated with lactic acid has been shown to reduce methane emissions by 25%. xx The costs will depend on the size of the herd, \$6 per $MTCO_2$ for a larger heard (>2500 cows), then increasing to \$9 per MTCO2 for a small herd (200-500 cows).xxi

Covering a lagoon with straw and a tight wooden lid has been shown to reduce emissions by up to 26%, depending on the climatexxii. Emissions reductions are more significant in warmer weather. The costs are the same as those for straw with lactic acid.

Converting manure storage a liquid to a solid could potentially reduce greenhouse gas emissions by as much as 90%xxiii. However, the costs are very high and would not be justifiable. Current planning regulations require any new dairy farms to have solid manure management, although the number of dairy farms is decreasing rather than increasing.

Anaerobic digestion (AD) is the other main option for manure management. It seems like a better option, as the gas can be collected for energy production, thereby allowing additional benefit through offsetting the use of high GWP fuels.

Historically the use of AD on dairy farms in CA has been attempted, but met with too many regulatory barriers[xxiv]. As of 2013, a new working group has combined various agencies to simplify the permitting process, and promote more widespread use of digesters with energy recovery, particularly targeting dairy farms, which produce 3.6 million tonnes of dry manure per year.[xxv]

Different types of AD are possible. The simplest is covered lagoon digestion. This reduces GHG emissions by up to 90%, plus offsets the use of other fuels for energy production at a rate of 0.00694 kWh per cow[xxvi]. The cost of building the facility is estimated at $0.75 million, plus $30,000 per year, with 1000 cows[xxi]. This method is only suitable for warmer climates.

Complete mixed or plug flow digestion is the second option. The benefits are the emissions reductions are the same as for covered lagoon digestion. The costs are higher, $1.5 million to start up, then $60,000 per year operational costs, for a farm with 1000 cows.[xxi]

The third option is co-digestion, where the animal waste is mixed with food waste. This increases the opportunities for revenue, as the plant could charge a gate fee for the food waste of $40-50 per tonne. The amount of gas generated would also be approximately double that of manure alone, doubling energy generation potential. However, the costs of developing the plant would also be almost double that of a manure only site, and operating costs up to four times higher.[xxi]

The above scenarios considered collecting the gas and converting to electricity. It would also be possible to use that gas for heating, or compress it for a vehicle fuel, but these options have been shown to be economically unfeasible for California. xxi

The use of AD also attracts subsidies from AB 32. However, in spite of the potential for revenue AD still works out to be an expensive option. The key California based case studies have found that farms would take somewhere between 10 and 30 years before the costs could be recovered from sale of gas etc. Government subsidies of at least 50% are usually required to make the plant feasible. xxi

Direct application of manures to land, as a soil conditioner was also considered. NI suggests savings of 0.4 t CO2eq compared to synthetic fertilizer usexxiii, however, other studies have found an increase in emissions. Overall the impacts are not well enough understood to accurately estimate emissions and costs savings.

4.6.3.3 Fertilizer use

The application of fertilizers can lead to significant emissions of N_2O both directly and indirectly. Optimizing the amount of fertilizer can reduce this risk, without affecting crop yields. The precise mechanisms which produce N_2O from soils are not well understood, but the following have been shown to reduce emissions of N_2O through experimentation.

Fertigation is an automated process, where fertilizer is distributed through an irrigation system. The system can be fitted with a computerized response feedback system which can measure moisture or climate, alerting the system to add more fertilizer, water or both. Although the precise emissions reductions are hard to predict, runoff has shown to be reduced by 23-60%. The costs of the system will obviously depend on the size of the crops and the type of crop. For set up the costs are likely to be around $22,000. The operational costs are more varied and will depend on the type of crop as well as the size of the propertyxxvii. xxviii

Less expensive options for fertilizers were also considered. Some suggestions included more accurate placement of fertilizers, placing smaller amounts of fertilizers more frequently. However, both these suggestions will have a significant increased labor cost, making them unrealistic for many farmersxxviii. Another more economically feasible option is to use slow release fertilizers, negating the need for additional fertilizer placement, while achieving the same affect. These costs around 10c more per pound than regular fertilizers,xxix and have been shown to reduce N_2O emissions by 35%xxviii.

Fertilizers with nitrification or urease inhibitors are also a more promising option. These inhibitors stop the formation of the bacteria the cause nitrification, for a period of time. Depending on the type, they have been shown to reduce N_2O emissions by between 10 and 38%. They cost about 10% more than regular fertilizers, but can reduced other costs, such as labor and fuel for vehicles used to spread the fertilizersxxviii.

4.6.3.4 Conservation tillage

Traditional tillage practices have been blamed for the significant release of carbon from soils. A huge amount of research into reducing tillage practices and the assessing the impact this has on soil carbon content is available, with many conflicting conclusions. Reviewing the literature indicated the main reason such a wide variety of conclusions exists is because the experimental approaches also varied widely. Many of the early studies measured soils to shallow depths, which found a significant increase in soil carbon content. However, following this research that measured soils at greater depth found the overall carbon content was the same it had just shifted into the shallower soils. Other studies took samples over much longer periods of time and found significant carbon increases occurred after many years. Many of these articles also failed to take account of the broader picture. For example they didn't consider the impact on crop yields. If these decreased due to the reduced tillage, then a greater area of land would be required to produce the same amount of produce, leading to an overall negative impact. Similarly, reduced tillage might lead to an increase in the use of pesticides and fertilizers, to try and combat the reduced yields. Both of these products have a carbon footprint, plus there would an increase in the use of vehicles to deliver these products to crops.

A more recent study by Sorenson et al.xxx took a more holistic life-cycle assessment approach to reducing tillage practices, including consideration of any change in crop yields. The results of this assessment therefore appear to the most realistic. They found that changing to a reduced tillage system lead to an overall reduction in greenhouse gas emissions of 10.7%, while a no-tillage system would reduce greenhouse gas emissions by 6.6%. The no tillage system also found a 10% reduction in yield, while the reduced tillage system maintained the same crop yield as the normal tillage approach. For both reduced and no-tillage the use of pesticides increased leading to an increase in costs of 22.5% for reduced and 25.2% for no-tillage. However, they also both lead to decrease in costs of diesel fuel and other vehicle related costs due to the reduction in use of tillage machinery. Therefore the costs are unlikely to be significantly different.

i ICF (2011) Development of the GHG refrigeration and air conditioning model. Prepared for the Department of Energy and Climate Change, UK. Available online: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48250/3844-greenhouse-gas-inventory-improvement-project-deve.PDF [Accessed November 5, 2014]

ii SKM (2012) Further assessment of policy options for the management and destruction of banks of ODS and F-gases in the EU. Prepared for the European Commissions. Available online http://ec.europa.eu/clima/policies/ozone/research/docs/ods_f-gas_destruction_report_2012_en.pdf [Accessed November 5, 2014]

iii USEPA (2014) GreenChill Partnership. Available online at http://www2.epa.gov/greenchill [Accessed November 5, 2014]

iv U.S. Green Building Council (2014) Refrigerant Management. Available online at http://www.usgbc.org/credits/ea7 [Accessed November 5, 2014] v USEPA (2013) Complying with the Section 608 refrigerant recycling rule. Available online: **http://www.epa.gov/ozone/title6/608/608fact.html** [Accessed November 5, 2014]

vi California Department of toxic substances control (2010) Certified Appliance Recycler program. Available online **http://www.dtsc.ca.gov/HazardousWaste/Mercury/Certified_Appliance_Recycler.cfm** [Accessed November 5, 2014]

vii USEPA (2013) Responsible Appliance Disposal Program 2012 annual report. Available online **http://www2.epa.gov/sites/production/files/2013-11/documents/rad_12_annual_report.pdf** [Accessed November 5, 2014]

viii USEPA (2014) NOPR: Protection of stratospheric ozone: Listing of substitutes for refrigeration and air conditioning and revision of the venting prohibition for certain refrigerant substitutes. 79FR 38811-38840.

ix Vetter and Ashford (2011) Developing a California inventory for ozone depleting substances (ODS) and hydrofluorocarbon (HFC) foam banks and emissions from foams. Report prepared for The California Air Resources Board and the California Environmental Protection Agency.

x USEPA (2013) An overview of landfill gas energy in the United States: USEPA landfill methane outreach program (LMOP). Available online: http://www.epa.gov/lmop/documents/pdfs/overview.pdf

xi USEPA (2014) Landfill Methane Outreach Program. Available online **http://www.epa.gov/lmop/** [Accessed November 6, 2014]

xii Marco Ritzkowski (2011) Landfill aeration: current and future applications. Presentation for Practitioners Workshop on CDM standards 8-10 June, 2011, Bonn. Available online **http://cdm.unfccc.int/methodologies/Workshops/cdm_standards/s4_tuh.pdf** [Accessed November 7, 2014]

xiii Personal Communication with Bill Grant, Blue Environment, Victoria.

xiv Calrecycle (2002) Case Study: San Francisco Fantastic three program. Available online **http://www.calrecycle.ca.gov/LGCentral/Library/innovations/curbside/CaseStudy.htm** [Accessed November 6, 2014]

xv CalRecycle (2013) Update on AB 341 Legislative Report: Statewide strategies to achieve the 75 percent goal by 2020. Available online **http://www.calrecycle.ca.gov/75Percent/UpdateOct13.pdf** [Accessed November 6, 2014]

xvi Waste Management World (2011) UK's largest anaerobic digestion food waste facility opened. Available online: **http://www.waste-management-world.com/articles/2011/06/uk-s-largest-anaerobic-digestion-food-waste-facility-opened.html** [Accessed November 6, 2014]

xvii VENTOUR, L. (2008) The food we waste. Waste and resources action program (WRAP). Available online: **http://wrap.s3.amazonaws.com/the-food-we-waste.pdf** [accessed November 6, 2014]

xviii Tom Quested, Robert Ingle and Andrew Parry (2013) Household food and drink waste in the United Kingdom 2012. Waste and Resources Action Program, UK.

xix USEPA (2014) Food Recovery Challenge. Avalable online **http://www.epa.gov/foodrecoverychallenge/** [accessed November 6, 2014]

xx Werner Berg, Reiner Brunsch, Imre Pazsiczki (2006) Greenhouse gas emissions from covered slurry compared with uncovered during storage. Agriculture, ecosystems and environment 112: 129-134.

xxi Hyunok Lee and Daniel Sumner (2014) Greenhouse gas mitigation opportunities in California Agriculture: Review of the Economics. Nicholas Institute Report. Available online **http://aic.ucdavis.edu/publications/california%20economics%20for%20GHG%20dduke%20report.pdf** [Accessed November 6, 2014]

xxii Joachim Clemens, Manfred Trimborn, Peter Weiland and Barbara Amon (2006) Mitigation of greenhouse gas emissions by anaerobic digestion of cattle slurry. Agriculture, Ecosystems and Environment 112: 171-177.

xxiii Justine J. Owen, Ermias Kebreab and Whendee Silver (2014) Greenhouse gas mitigation opportunities in California Agriculture: Review of emissions and mitigation potential of animal manure management and land application of manure. Available online http://www.nicholasinstitute.duke.edu/ecosystem/publications/greenhouse-gas-mitigation-opportunities-california-agriculture-review-emissions-and#.VFrJDMmTCxo [Accessed November 6, 2014]

xxiv CalEPA (2011) History: Anaerobic Digesters at Dairies in California. Available online http://www.calepa.ca.gov/digester/History.htmFertilizer Use [Accessed November 6, 2014]

xxv California/Federal Dairy Digester Working Group (2013) Statement of Principles. Available online
http://www.cdfa.ca.gov/EnvironmentalStewardship/Dairy_Digesters.html
[Accessed November 6, 2014]

xxvi David Schmidt (2002) Anaerobic digestion overview. Available online http://www.extension.umn.edu/agriculture/manure-management-and-air-quality/manure-treatment/docs/anaerobic-digestion-overview.pdf [Accessed November 6, 2014]

xxvii R. Lal (2004) Soil carbon sequestration to mitigate climate change. Geoderma 123: 1-22.

xxviii C.S. Snyder, T.W. Bruulsema, T.L. Jensen and P.E. Fixen (2009) Review of greenhouse gas emissions from crop production systems and fertilizer management effects. Agriculture, Ecosystems and Environment 133: 247-266.

xxix George Silva (2011) Slow release nitrogen fertilizers. Available online

http://msue.anr.msu.edu/news/slow_release_nitrogen_fertilizers [Accessed

November 6, 2014]

xxx Claus G. Sorensen, Niels Halberg, Frank W. Oudshoorn, Bjorn M. Petersen and Randi Dalgaard (2014) Energy inputs and GHG emissions of tillage systems. Biosystems Engineering 120: 2-14.