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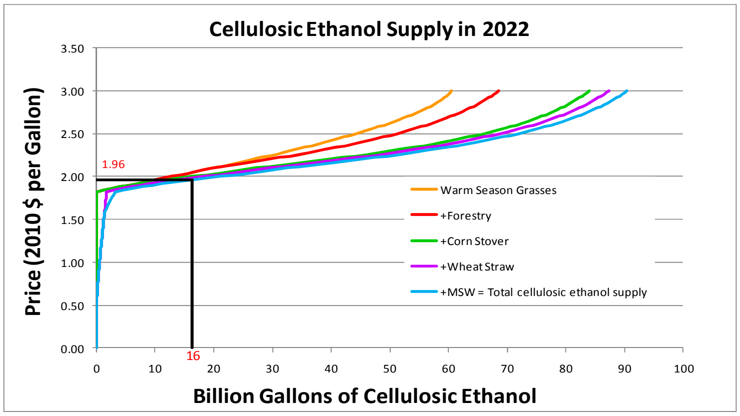
Biomass

The objective is to represent the supply of five forms of biomass to two uses. The types of biomass are warm season grasses such as switchgrass and miscanthus, forest material, corn stover, wheat straw, and municipal solid waste. The two uses are for biofuel and bioelectricity.

Biomass supplies are based on a meta-analysis. This meta-analysis gathered pairs of cellulosic biofuel or biomass prices and quantities from recent studies, rendered them comparable, and regressed over these pairs to determine supply curves.[1] The outcome is represented as a set of supply curves for cellulosic ethanol from each category of biomass (Figure 1). The cumulative supply curve in 2022 based on the studies used might be characterized as optimistic, with the 16 billion gallon cellulosic biofuel mandate met at a cellulosic ethanol price of $1.96, and a quickly increasing aggregate cellulosic ethanol supply if the price increases beyond that point.

Figure 1. Results of cellulosic biofuel supply curve meta-analysis.



The supply curves from that meta-analysis are subject to further adjustment before they can be applied here. The technical parameters are updated somewhat, where possible, based on more recent publications. Moreover, some judgments were made to weight the most recent estimates of biomass costs and yields over the older estimates, as experiences to date suggest that initial estimates of biomass production, transportation, and processing appear to have been too optimistic. The functional form was also adjusted somewhat. For example, cross-commodity effects are explicitly represented so changes in other crop prices will affect the biomass supply curve.

The other change is to allow for two possible uses of biomass. It was decided not to represent the market for any form of biomass as a single aggregate market for a mostly homogeneous good. The main reason is that this form of market structure is viewed as unlikely, at least for the near term given expectations about technologies available. First, these forms of biomass are low density commodities, so transportation costs are likely to prohibit shipping biomass over even a modest distance. Second, there is a likelihood of dedicated capital investments on the part of biomass producer, who might have to plant a specialized perennial or tree, and the processor who needs these feedstocks. Dedicated investments suggest that contracts might be used to lock in agreements for most of the transactions rather than spot markets. Given transportation costs and dedicated investments, the representation is based on the view that biomass will mostly be grown and traded under contracts. Nevertheless, we allow for some competition between uses, with increased biomass for one purpose coming in part at the expense of biomass available for the other purpose. The argument for some competition is that processors might compete in an area for biomass, or simply buy from one another if there is profit in it, and biomass supplies to the two uses might compete for inputs, such as land, causing some indirect competition.

[1] This meta-analysis is reported in Steiner and Thompson, "Meta-Analysis of Cellulosic Ethanol Supply", poster presented at the University of Missouri Undergraduate Research Forum in 2011.

Variables in the biomass module

Note: In the tables and equations below, the symbol @ is used in place of feedstock notations WG (warm season grasses); WS (wheat straw); ST (corn stover); FM (forest materials); and MW (municipal waste).

NAME	DESCRIPTION	SOURCE
@ELCR	Feedstock corn area effects (EL)	Assumed
@ELCTEK	Cost trend (EL), growth rate (2022 = 1)	Assumed
@ELCVTR	Transportation cost trend (EL), $/dry ton	Assumed
@ELINT	Calibration intercept (EL)	Assumed
@ELOTC	Other costs (EL), $/btu	EIA Electric Power Annual 2010
@ELPFRM	Feedstock farm price (EL), $/dry ton	Assumed
@ELPPLT	Feedstock plant price (EL), $/dry ton	Calculated
@ELPTEK	Production cost trend (EL), $/dry ton	Assumed
@ELQ	Feedstock EL use effects (LF)	Assumed
@ELSB	Feedstock soybean area effects (EL)	Assumed
@ELSPRD	Feedstock production for EL, million dry tons	Calculated
@ELTRAN	Transportation cost (EL), $/dry ton	Calculated
@ELTVC	Non-Petrol transport costs (EL), $/dry ton	Assumed
@ELWH	Feedstock wheat area effects (EL)	Assumed
@LFCR	Feedstock corn area effects (LF)	Assumed
@LFCTEK	Cost trend (LF), growth rate (2022 = 1)	Assumed
@LFCVTR	Transportation cost trend (LF), $/dry ton	Assumed
@LFINT	Calibration intercept (LF)	Assumed
@LFOTC	Other costs (LF), $/dry ton	DOE MYPP, 2011
@LFPFRM	Feedstock farm price (LF) $/dry ton	Calculated
@LFPPLT	Feedstock plant price (LF), $/dry ton	Calculated
@LFPTEK	Production cost trend, $/dry ton	Assumed
@LFQ	Feedstock LF use effects (EL)	Assumed
@LFSB	Feedstock soybean area effects (LF)	Assumed
@LFSPRD	Feedstock production for LF, million dry tons	Calculated
@LFTRAN	Transportation cost (LF), $/dry ton	Calculated
@LFTVC	Non-Petrol transport costs (LF), $/dry ton	Assumed
@LFWH	Feedstock wheat area effects (LF)	Assumed
BPYLD@	By-product yield, index	Assumed
CRENRS1	Expected net returns from corn production, $/acre	FAPRI-MU
ELCCAP@	Feedstock specific processing cost of capital (EL), $/dry ton	DOE MYPP, 2011
ELNINDEX	Conventional electricity price index	Assumed
ELRINDEX	Renewable electricity price index	Assumed
ELSPRD@	EL production by feedstock, trillion btu	Calculated
ELSPRDBM	Electricity production from all biomass, trillion btu	Calculated
ELYLD@	Electricity yield, btu/dry ton	EERE, 2011; Phyllis Database
ELYLLF@	Electricity yield, kWh/gallon LF produced	DOE MYPP, 2011
ENELSSBB_RATE	Federal grant rate as percent of costs	DSIRE, 2011
ENELSSBF_UNIT	Tax credits for renewable energy excluding hydro, $/watt	DSIRE, 2011
ESUBEL@	Establishment subsidy for feedstock (EL), $/ dry ton	Assumed
ESUBLF@	Establishment subsidy for feedstock (LF), $/ dry ton	Assumed
ETCOIL@	Oil cost (LF), $/gallon	Kazi et al., 2010
ETNGAS@	Natural gas cost (LF), $/gallon	Kazi et al., 2010
ETPBP@	By-product price (LF), $/dry ton	Assumed
ETPCEL	Cellulosic ethanol price, $/gallon	Calculated
ETPSUB@	Ethanol producer subsidy, $/gallon	Assumed
ETYLD@	Ethanol yield, gallons/ dry ton of feedstock	EERE, 2011; Phyllis Database
LFCCAP@	Feedstock specific processing cost of capital (LF), $/gallon	DOE MYPP, 2011
LFSPRD@	LF production by feedstock, million gallons	Calculated
LFSPRDBM	Liquid fuel production from all biomass, million gallons	Calculated
PDC2022	Price deflator, index (2022 = 1)	Calculated
POILRASA	Refiners' crude oil acquisition price, marketing year, $/barrel	FAPRI-MU
PPINGAS1	Natural gas price index,	FAPRI-MU
PPIRPPSA	Refiners' petroleum product price index, marketing year, index	FAPRI-MU
PSUBEL@	Producer subsidy for feedstock (EL), $/ dry ton	Assumed
PSUBLF@	Producer subsidy for feedstock (LF), $/ dry ton	Assumed
SBENRS1	Expected net returns from soybean production, $/acre	FAPRI-MU
WGSHAR	Warm grasses area harvested, million acres	FAPRI-MU
WGSPLT	Warm grasses area planted, million acres	FAPRI-MU
WGSYLD	Warm grasses yield, dry tons/acre	FAPRI-MU
WHENRS1	Expected net returns from wheat production, $/acre	FAPRI-MU

Biomass module technical parameters

The following table presents the initial assumptions made regarding technical parameter values.

NAME	DESCRIPTION	UNIT	VALUE		
			1978-2009	1980-1989	1990-2009
@ELCR	WS, ST, MW		0	0	0
	WG		0.1	0.1	0.1
	FM		0.05	0.05	0.05
@ELCTEK			1	1	1
@ELCVTR		$/dry ton	1	1	1
@ELINT			0	0	0
@ELOTC	WG, WS, ST, FM	$/btu	1.47e-5	1.53e-5	1.47e-5
	MW	$/btu	2.11e-5	2.35e-5	2.02e-5
@ELPFRM		$/dry ton	40	40	40
@ELPPLT		$/dry ton	80	80	80
@ELPTEK		$/dry ton	0.51	0.40	0.58
@ELQ			0.5	0.5	0.5
@ELSB	WS, ST, MW		0	0	0
	WG		0.1	0.1	0.1
	FM		0.05	0.05	0.05
@ELSPRD			0	0	0
@ELTRAN		$/dry ton	30	30	30
@ELTVC		$/dry ton	7.06	0	11.3
@ELWH	WS, ST, MW		0	0	0
	WG		0.2	0.2	0.2
	FM		0.05	0.05	0.05
@LFCR	WS, ST, MW		0	0	0
	WG		0.1	0.1	0.1
	FM		0.05	0.05	0.05
@LFCTEK		$/dry ton	2.07	2.53	1.76
@LFCVTR		$/dry ton	1	1	1
@LFINT			0	0	0
@LFOTC	WG, WS, ST	$/dry ton	0.85	0.65	0.99
	FM, MW	$/dry ton	1.87	1.49	2.14
@LFPFRM		$/dry ton	40	40	40
@LFPPLT		$/dry ton	80	80	80
@LFPTEK		$/dry ton	0.51	0.40	0.58
@LFQ			0.5	0.5	0.5
@LFSB	WS, ST, MW		0	0	0
	WG		0.1	0.1	0.1
	FM		0.05	0.05	0.05
@LFSPRD		Million gallons	0	0	0
@LFTRAN		$/dry ton	30	30	30
@LFTVC		$/dry ton	7.06	0	11.3
@LFWH	WS, ST, MW		0	0	0
	WG		0.2	0.2	0.2
	FM		0.05	0.05	0.05
BPYLD@		Index	1	1	1
CRENRS1		$/acre	62.87	0	100.59
ELCCAP@		$/dry ton	0	0	0
ELNINDEX		Index	1	1	1
ELRINDEX		Index	1	1	1
ELSPRD@	WG,WS,ST	Trillion btu	0.77	0	1.23
	MW	Trillion btu	36.11	0	57.78
	FM	Trillion btu	78.80	0	126.09
ELSPRC@	WG,WS,ST	Trillion btu	0	0	0
	MW	Trillion btu	0	0	0
	FM	Trillion btu	0	0	0
ELSPRDBM		Trillion btu	122.05	15.18	187.55
ELYLD@	WG	Btu/dry ton	5538921	5538921	5538921
	WS	Btu/dry ton	5475078	5475078	5475078
	ST	Btu/dry ton	5215192	5215192	5215192
	FM	Btu/dry ton	5653054	5653054	5653054
	MW	Btu/dry ton	5569637	5569637	5569637
ELYLLF@	WG, WS, ST	kWh/gallon	5.7	5.7	5.7
	FM, MW	kWh/gallon	8.4	8.4	8.4
ENELSSBB_RATE		Percent	0.01	0	0.02

ENELSSBF_UNIT		$/watt	0.06	0.01	0.09
ESUBEL@		$/dry ton	0	0	0
ESUBLF@		$/dry ton	0	0	0
ETCOIL@		$/gallon	0	0	0
ETNGAS@		$/gallon	0	0	0
ETPBP@		$/dry ton	0	0	0
ETPCEL		$/gallon	1.51	1.36	1.57
ETPSUB@		$/dry ton	0	0	0
ETYLD@	WG	Gallons/dry ton	82.73	82.73	82.73
	WS	Gallons/dry ton	79.65	79.65	79.65
	ST	Gallons/dry ton	22.47	0	35.95
	FM	Gallons/dry ton	68.4	68.4	68.4
	MW	Gallons/dry ton	89.55	89.55	89.55
LFCCAP@	WG, WS, ST	$/dry gallon	1.08	0.83	1.26
	FM, MW	$/dry gallon	1.28	1.01	1.48
LFSPRD@		Million gallons	0	0	0
LFSPRDBM		Million gallons	0	0	0
PDC2022		Index (2022 =1)	0.57	0.44	0.66
POILRASA		$/barrel	28.98	23.90	34.42
PPINGAS1		Index	132.51	88.23	157.70
PPIRPPSA		Index	0.88	0.56	1.12
PSUBEL@		$/dry ton	0	0	0
PSUBLF@		$/dry ton	0	0	0
SBENRS1		$/acre	50.54	0	80.87
WGSHAR		Million acres	0	0	0
WGSPLT		Million acres	0	0	0
WGSYLD		Dry tons/acre	4.48	.	4.48
WHENRS1		$/acre	26.47	0	42.36

Biomass module equations

The equations for feedstock prices at the liquid fuel (LF) and electric power (EL) plant gates take the following general forms. Note that liquid fuel processing is also a net producer of renewable electricity:

```
@LFPPLT = ETPCEL*ETYLD@
            + ETPBP@*BPYLD@
            + ETPSUB@*ETYLD@
            - @LFCTEK*( ETNGAS@*(1/3*lag(PPINGAS1)+2/3*PPINGAS1)
                              + ETCOIL@*(POILRASA/2 + lag(POILRASA)/2)
                              + @LFOTC*ETYLD@)
                     + (ELRINDEX*3412/1000000)*ELYLLF@*ETYLD@
            - LFCCAP@*ETYLD@


@ELPPLT = (ELYLD@/1000000)*(ELRINDEX)
            - @ELCTEK*(@ELOTC)
            - (ELCCAP@*(1-ENELSSBB_RATE) - ENELSSBF_UNIT*7008*3412/1000000)
```

Transportation costs vary by type of feedstock, but the same general form is used for the liquid fuel and electric power versions.

```
WGLFTRAN = 0 + WGLFTVC*WGLFCVTR + 7.008928703*PPIRPPSA/1.806
WSLFTRAN = 0 + WSLFTVC*WSLFCVTR + 10.60452251*PPIRPPSA/1.806
FMLFTRAN = 0 + FMLFTVC*FMLFCVTR + 7.008928703*PPIRPPSA/1.806
STLFTRAN = 0 + STLFTVC*STLFCVTR + 10.60452251*PPIRPPSA/1.806
MWLFTRAN =20 + MWLFTVC*MWLFCVTR + 7.008928703*PPIRPPSA/1.806
```

The feedstock production equations for liquid fuel and electric power end uses also are estimated using the same general form that varies by type of feedstock (electricity use is shown below).

```
WGELSPRD = max( 0, ELWGSADJ
      + WGELPTEK*(310.177/2 + WGELINT
      + 89.43832919*(max(0.0,
            ((PSUBELWG + ESUBELWG + WGELPFRM))/PDC2022))**0.5
      *((CRENRS1 + STNRPTON*(STLFSPRD+STELSPRD)/CRSHAR1)/PDC2022 )**(WGELCR)
      *(SBENRS1/PDC2022)**(WGELSB)
      *((WHENRS1 + WSNRPTON*(WSLFSPRD+WSELSPRD)/WHSHAR1)/PDC2022)**(WGELWH))
      - WGLFQ*max(0, WGLFSPRD-10) + EBMASS21)

WSELSPRD = max(0,  ELWSSADJ
      + WSELPTEK*(12.67533/2 + WSELINT
      + 5.491053383*(max(0.0,
            ((PSUBELWS + ESUBELWS + WSELPFRM))/PDC2022)) **0.5
      + WSELCR*log(lag(WHSPRD1)))
      - WSLFQ*max(0, WSLFSPRD-10) + EBMASS22)


FMELSPRD = max(0,  ELFMSADJ
      + FMELPTEK*(70.09523/2 + FMELINT
      + 38.46741837*(max(0.0,
            ((PSUBELFM + ESUBELFM + FMELPFRM))/PDC2022))**0.5
      *((CRENRS1 + STNRPTON*(STLFSPRD+STELSPRD)/CRSHAR1)/PDC2022)**(FMELCR)
      *(SBENRS1/PDC2022)**(FMELSB)
      *((WHENRS1 + WSNRPTON*(WSLFSPRD+WSELSPRD)/WHSHAR1)/PDC2022)**(FMELWH))
      - FMLFQ*max(0, FMLFSPRD-10) + EBMASS23)

STELSPRD = max(0, ELSTSADJ
      + STELPTEK*(93.76518/2 + STELINT
      + 19.84742072*(max(0.0,
            ((PSUBELST + ESUBELST + STELPFRM))/PDC2022))**0.5
      + STELCR*log(lag(CRSPRD1)))
      - STLFQ*max(0, STLFSPRD -10)  + EBMASS24   )

MWELSPRD = max(0,
      MWELPTEK*(38/2 + MWELINT
      + 1.906151666*(max(0.0,
            ((PSUBELMW + ESUBELMW + MWELPFRM))/PDC2022))**0.5)
      - MWLFQ*max(0, MWLFSPRD -5) + EBMASS25   )


LFSPRD@ = @LFSPRD*ETYLD@

ELSPRD@ = (ELYLD@/1000000000000)*@ELSPRD*1000000
```

Net electricity production from the conversion of feedstocks to liquid fuels.

```
ELSPRC@ = (@LFSPRD*1000000*ELYLLF@*ETYLD@*3412/1000000000000)

LFSPRDBM = LFSPRDWG + LFSPRDWS + LFSPRDFM + LFSPRDST + LFSPRDMW

ELSPRDBM = ELSPRDWG + ELSPRDWS + ELSPRDFM + ELSPRDST + ELSPRDMW
         + ELSPRCWG + ELSPRCWS + ELSPRCFM + ELSPRCST + ELSPRCMW         -

WGSHAR = (WGLFSPRD + WGELSPRD)/WGSYLD + EBMASS43;
```

```
WGSHAR = 0.95*WGSPLT
```

Farm prices for a particular feedstock and end use are calculated as the plant price less transportation costs.

```
@ELPFRM = @ELPPLT - @ELTRAN
@LFPFRM = @LFPPLT - @LFTRAN
```

Natural gas market

The EIA Annual Energy Review 2010 provides natural gas demand data for five consumption sectors (Industrial, Residential, Commercial, Electric Power, and Transportation), exports, and additions to storage. Natural gas is an important input in both fertilizer and ethanol production, so we disaggregate industrial consumption into four crop types (Corn, Cotton, Soybean, and Wheat) and ethanol plant consumption. Thus, we are able to account for these agricultural uses of natural gas separately and with more precision in the baseline and scenario analyses. The crop uses were calculated using fertilizer and herbicide application rates from NASS Agricultural Resource Management Surveys and assumed direct use values of 21.5 m^3/ ha and 3.7 m^3/ ha for corn and soybeans, respectively. Ethanol plant consumption is calculated using ethanol production data from the FAPRI-MU baseline as well as an assumed use rate of 27,611 Btu/gallon ethanol produced (BESS v2008.3.0). Nitrogen exports are also included and were calculated using data from the US International Trade Commission.

From Table 1, it is clear to see that non-agricultural, industrial uses of natural gas are the dominant demand sector followed by the residential sector. Crop uses of natural gas have held fairly steady over the period studied while the surge is ethanol production is evident. The growing use of natural gas as a peak-load input in electricity generation can be seen in the increasing share of natural gas use by the electric power sector. Export demand has also increased rapidly in recent times. Transportation uses of natural gas remain small as there are relatively few vehicle fleets powered by natural gas.

The supply data remain fairly unchanged from the Annual Energy Review. However, we add a category, nitrogen imports, to balance the nitrogen export category on the demand side. The general trend is that natural gas production has been increasing over time as have nitrogen imports. The expectation is that recent shale gas discoveries will serve to boost domestic natural gas reserves and, likely, production well into the future.

Table 1. Natural gas quantities and shares

	1969-2009		**1970-79**		**1980-89**		**1990-2009**	
				Trillion Btu				
Natural Gas Supply Variables								
Total U.S. Production	19445	80%	20927	88%	17889	84%	19432	75%
Total Imports	2197	9%	1022	4%	1026	5%	3442	13%
Supplemental Fuels	105	0%	NA	.	131	1%	93	0%
Withdrawals	2475	10%	1814	8%	2237	11%	2977	11%
Nitrogen Imports	379	2%	.	.	66	0%	457	2%
Total Supply	24424		23763		21316		26400	
Natural Gas Demand Variables								
Industrial Consumption, Adjusted	8320	34%	9347	40%	7200	34%	8320	32%
Ethanol Plant Consumption	73	0%	.	.	21	0%	89	0%
Corn Production Consumption	263	1%	.	.	278	1%	259	1%
Cotton Production Consumption	35	0%	.	.	32	0%	36	0%
Soybean Production Consumption	60	0%	.	.	58	0%	61	0%
Wheat Production Consumption	111	0%	.	.	135	0%	104	0%
Nitrogen Exports	117	0%	.	.	196	1%	97	0%
Residential Consumption	4910	20%	5079	22%	4675	22%	4945	19%
Commercial Consumption	2851	12%	2653	11%	2605	12%	3099	12%
Transportation Consumption	647	3%	662	3%	582	3%	672	3%
Electric Power Consumption	4214	17%	3619	15%	3176	15%	5063	19%
Total Consumption	21357	88%	21360	91%	18648	89%	22743	87%

Total Exports	249	1%	70	0%	64	0%	440	2%
Additions	2566	11%	2071	9%	2223	11%	3036	12%
Total Demand	24425		23502		20936		26219	

Source: EIA, NASS, USITC, FAPRI-MU
Note: Totals may not sum due to rounding errors

Variables in the natural gas module

Name	Description	Source
CRSPLT	Corn area planted, marketing year, thousand acres	FAPRI-MU
CTSPLT	Cotton area planted, marketing year, thousand acres	FAPRI-MU
ENCLPBIT	Bituminous coal price, $/million btu	EIA historical data, AEO 2011 from 2008
ENELPCOM	Commercial electricity price, $/million btu	EIA historical data, AEO 2011 from 2008
ENELPIND	Industrial electricity price, $/million btu	EIA historical data, AEO 2011 from 2009
ENELPRES	Residential electricity price, $/million btu	EIA historical data, AEO 2011 from 2007
ENNGDADD	Additions to natural gas storage, trillion btu	EIA historical data, AEO 2011 from 2007
ENNGDCOM	Commercial natural gas consumption, trillion btu	EIA historical data, AEO 2011
ENNGDCR	Corn production use of natural gas, trillion btu	Calculated using NASS application rates
ENNGDCT	Cotton production use of natural gas, trillion btu	Calculated using NASS application rates
ENNGDELS	Electric power natural gas consumption, trillion btu	EIA historical data, AEO 2011
ENNGDET	Ethanol plant natural gas consumption, trillion btu	Calculated using BESS parameters
ENNGDEXP	Natural gas exports, trillion btu	EIA historical data, AEO 2011
ENNGDIND_ADJ	Industrial natural gas consumption, adjusted, trillion btu	EIA historical data, AEO 2011
ENNGDRES	Residential natural gas consumption, trillion btu	EIA historical data, AEO 2011
ENNGDSB	Soybean production use of natural gas, trillion btu	Calculated using NASS application rates
ENNGDTRN	Transportation natural gas consumption, trillion btu	EIA historical data, AEO 2011
ENNGDWH	Wheat production use of natural gas, trillion btu	Calculated using NASS application rates
ENNGPCOM	Commercial natural gas price, $/million btu	EIA historical data, AEO 2011
ENNGPELS	Electric power natural gas price, $/million btu	EIA historical data, AEO 2011
ENNGPIND	Industrial natural gas price, $/million btu	EIA historical data, AEO 2011
ENNGPRES	Residential natural gas price, $/million btu	EIA historical data, AEO 2011
ENNGPWHD	Wellhead natural gas price, $/million btu	EIA historical data, AEO 2011
ENNGPWHD_S	Supply inducing wellhead natural gas price, $/million btu	Calculated
ENNGSEQC	Natural gas production drilling and equipment cost, thousand $/well	EIA historical data
ENNGSIMP	Natural gas imports, trillion btu	EIA historical data, AEO 2011
ENNGSOPC	Natural gas production operating cost, $/million btu	EIA historical data
ENNGSPRD	Natural gas production, trillion btu	EIA historical data, AEO 2011
ENNGSSF	Supplemental fuels, trillion btu	EIA historical data, AEO 2011
ENNGSWDR	Withdrawals from natural gas storage, trillion btu	EIA historical data
ETSPRDCL	Ethanol production, calendar year, million gallons	FAPRI-MU
NITDEXP	Nitrogen exports, trillion btu natural gas equivalents	US International Trade Commission
NITSIMP	Nitrogen imports, trillion btu natural gas equivalents	US International Trade Commission
POPTOTW	Population, millions	FAPRI-MU
PPI	Producer price index (1986=Base Year)	FAPRI-MU
RGDPCA	Real Canadian GDP, billion $ (2005=Base Year)	USDA ERS
RGDPMX	Real Mexican GDP, billion $ (2005=Base Year)	USDA ERS
SBSPLT	Soybean area planted, marketing year, thousand acres	FAPRI-MU
WHSPLT	Wheat area planted, marketing year, thousand acres	FAPRI-MU
ZCE92W	Real consumer expenditures, million $	FAPRI-MU

Natural gas module equations

All the equations in the natural gas module are estimated using the double-log functional form. This implies that the estimated elasticities can be read directly from the parameter estimates. Also, the double-log form implies that the elasticities will be constant. In the demand equations, the price effects are estimated using a ratio of the input price (natural gas price for that particular sector) as the numerator and the price of a competing energy good (coal or electricity price for that sector) as the denominator. A further implication of such a ratio in a double-log equation is that the own- and cross price demand elasticities will be equal in magnitude and opposite in sign. Thus, the competing goods are assumed to be substitutes rather than complements.

```
log(ENNGDELS)  =              - 0.80
                              - 0.06 * log(ENNGPELS/ENCLPBIT)
                              + 0.24 * log(ZCE92W)
                              + 0.86 * log(lag(ENNGDELS))

 log(ENNGDIND_ADJ)  =         + 0.22
                              - 0.13 * log(ENNGPIND/(ENELPIND))
                              + 0.08 * log(ZCE92W)
                              + 0.88 * log(lag(ENNGDIND_ADJ))

 log((ENNGDRES/POPTOTW)) =    + 1.84
                              - 0.13 * log(ENNGPRES/(ENELPRES))
                              + 0.1   * log(ZCE92W/POPTOTW)
                              + 0.26 * log(lag(ENNGDRES/POPTOTW))
                              - 0.005 * (ZTIME-1970)

log(ENNGDCOM)  =              + 0.87
                              - 0.16 * log(ENNGPCOM/(ENELPCOM))
                              + 0.21 * log(ZCE92W)
                              + 0.65 * log(lag(ENNGDCOM))

log(ENNGDEXP)  =              - 12.81
                              - 0.03 * log(ENNGPWHD/PPI)
                              + 1.66 * log(RGDPCA)
                              + 0.58 * log(RGDPMX)
                              + 0.75 * log(lag(ENNGDEXP))
                              - 0.03 * (ZTIME-1970)

ENNGDCR =     (7.296771*948600 + 21.5*35.314*1031)*CRSPLT/2471000

ENNGDSB =     (2.092039*948600 + 3.7*35.314*1031)*SBSPLT/2471000

ENNGDCT =     (6.554944*948600)*CTSPLT/2471000

ENNGDWH =     (3.985969*948600)*WHSPLT/2471000

ENNGDET =     ETSPRDCL*26711/1000000

log(ENNGSPRD) =               + 1.42
                              + 0.25 * log(ENNGPWHD_S/PPI)
                              - 0.16 * (ENNGSOPC/PPI)
                              - 0.09 * log(ENNGSEQC/PPI)
                              + 0.9   * log(lag(ENNGSPRD))
                              + 0.0005 * (ZTIME-1970)

log(ENNGSIMP) =               + 4.78
                              + 0.21 * log(ENNGPWHD/PPI)
                              - 0.65 * log(RGDPCA)
                              + 0.87 * log(lag(ENNGSIMP))
                              + 0.02 * (ZTIME-1970)

ENNGSBAL =  + ENNGDRES
            + ENNGDIND_ADJ
            + ENNGDCOM
            + ENNGDELS
            + ENNGDTRN
```

```
                + ENNGDET
                + ENNGDCR
                + ENNGDSB
                + ENNGDCT
                + ENNGDWH
                + ENNGDEXP
                + ENNGDADD
                + NITDEXP
                - ENNGSPRD
                - ENNGSIMP
                - ENNGSSF
                - ENNGSWDR
                - NITSIMP

log(ENNGPRES) =               + 0.94
                              + 0.50 * log(ENNGPWHD)
                              + 0.02 * (ZTIME-1970)

log(ENNGPIND) =               + 0.64
                              + 0.83 * log(ENNGPWHD)
                              - 0.003 * (ZTIME-1970)

log(ENNGPCOM) =               + 0.85
                              + 0.62 * log(ENNGPWHD)
                              + 0.01 * (ZTIME-1970)

log(ENNGPELS) =               + 0.49
                              + 0.93 * log(ENNGPWHD)
                              - 0.007 * (ZTIME-1970)

ENNGPWHD_S = ENNGPWHD
```

Coal market

The coal market model includes endogenous production, domestic industrial and electricity uses, and exports. The bituminous coal price clears the market.

An aside: homogeneous coal?

The treatment of coal as a homogenous good ignores certain realities. For example, anthracite, bituminous, sub bituminous, and lignite have different heat, sulfur, and mercury content.[2] Some types of coal are better suited for some uses, such as "low-ash, low-sulfur bituminous coal" used for steel making.[3] After examining the data with a focus in particular on the most recent years, we judge that this treatment of coal is appropriate for our purposes because the role of non-electricity uses in the coal market is quite small and because most of the prices are strongly linked to one another, suggesting substantial willingness to substitute among coal types at least for a range of marginal uses.

Table 2. Coal Market Quantities and Shares.

	1969-2009		1970-79		1980-89		1990-99		2000-09	
					(Million Short Tons)					
Coal Supply Variables										
Total U.S. Production	912	83%	647	84%	879	80%	1041	85%	1116	84%
Bituminous	594	54%	564	73%	624	57%	635	52%	559	42%
Subbituminous	251	23%	56	7%	184	17%	313	26%	475	36%
Lignite	63	6%	21	3%	67	6%	88	7%	81	6%
Anthracite	4	0%	7	1%	4	0%	4	0%	2	0%
Total Imports	9	1%	1	0%	2	0%	7	1%	26	2%
Waste	9	1%	n.a.	n.a.	1	0%	7	1%	12	1%
Beginning Stocks	169	15%	124	16%	212	19%	172	14%	175	13%
Total Supply	1094		772		1093		1226		1330	
Coal Demand Variables										
Industrial Consumption	116	11%	154	20%	116	11%	104	9%	82	6%
Residential Consumption	2	0%	4	1%	2	0%	1	0%	0	0%
Commercial Consumption	5	1%	7	1%	6	1%	5	0%	4	0%
Electric Power Consumption	725	66%	412	53%	668	61%	858	70%	1004	76%
Total Consumption	848	78%	577	75%	791	72%	968	79%	1090	82%
Total Exports	72	7%	59	8%	92	8%	86	7%	54	4%
Ending Stocks	172	16%	136	18%	209	19%	173	14%	180	14%
Total Demand	1093		771		1092		1227		1324	

Source: calculations based on EIA data.

Data representing coal market supplies and demands suggest that the dominant use is electricity, accounting for two-thirds of total demand over the period from 1969 to 2009 and 75% in the most recent 10-year period for which data are available (Table). In the 2000-2009 period, 92% of domestic use of coal was for electricity generation. Industrial uses accounted for 11% of total coal use, on average, of the 1969-2009 period, but only 6% in the final 10 years of these data. Moreover, if coal for steel making, one of the main industrial uses, is chiefly bituminous, then it cannot be more than a small part of the total coal produced each year. Thus, industrial and electricity uses are more likely to be competing for the same type of coal.

Correlation among nominal coal and electricity prices over the 1969 to 2009 period tend to be quite strong, with no value of 0.80 or lower (Table). However, the relationship among prices was not as firm in the 1980s if judged by the links between electricity and coal prices, excluding lignite, and

[2] See www.eia.gov/energy_in_brief/role_coal_us.cfm.
[3] See www.eia.gov/cneaf/coal/page/acr/acr.pdf.

comparing lignite price to other coal prices. The data representing prices in 2000-2009 are more correlated, with values of at least 0.70 and often closer to 1.00. The correlation among electricity prices is quite strong at all times. Estimated links among prices in the period from 1989 to 2009 suggest high explanatory power overall, excluding anthracite, and signs of slope parameters match expectations (Table).

Table 3. Correlation of nominal coal and electricity prices.

1969 to 2009	*Elec. Residential*	*Elec. Commercial*	*Elec. Industrial*	*Elec. Transportation*	*Coal Lignite*	*Coal Anthracite*	*Coal Bituminous*
Electricity Residential	1.00						
Electricity Commercial	1.00	1.00					
Electricity Industrial	0.98	0.99	1.00				
Electricity Transportation	0.98	0.97	0.96	1.00			
Coal Lignite	0.98	0.97	0.97	0.98	1.00		
Coal Anthracite	0.81	0.84	0.88	0.82	0.83	1.00	
Coal Bituminous	0.85	0.87	0.91	0.91	0.90	0.91	1.00

1979 to 1990	*Elec. Residential*	*Elec. Commercial*	*Elec. Industrial*	*Elec. Transportation*	*Coal Lignite*	*Coal Anthracite*	*Coal Bituminous*	*Coal Subbituminous*
Electricity Residential	1.00							
Electricity Commercial	0.99	1.00						
Electricity Industrial	0.92	0.96	1.00					
Electricity Transportation	0.98	0.97	0.95	1.00				
Coal Lignite	0.95	0.97	0.95	0.93	1.00			
Coal Anthracite	0.21	0.31	0.53	0.33	0.33	1.00		
Coal Bituminous	-0.01	0.15	0.36	0.09	0.17	0.78	1.00	
Coal Subbituminous	0.20	0.35	0.56	0.30	0.41	0.86	0.92	1.00

2000 to 2009	*Elec. Residential*	*Elec. Commercial*	*Elec. Industrial*	*Elec. Transportation*	*Coal Lignite*	*Coal Anthracite*	*Coal Bituminous*	*Coal Subbituminous*
Electricity Residential	1.00							
Electricity Commercial	0.99	1.00						
Electricity Industrial	0.99	1.00	1.00					
Electricity Transportation	0.98	0.98	0.98	1.00				
Coal Lignite	0.91	0.86	0.87	0.92	1.00			
Coal Anthracite	0.72	0.73	0.71	0.78	0.72	1.00		
Coal Bituminous	0.98	0.97	0.97	0.99	0.94	0.73	1.00	
Coal Subbituminous	0.98	0.95	0.96	0.98	0.96	0.76	0.98	1.00

Source: calculations based on EIA data.

Table 4. Estimated price links, double-log regressions, 1989-2009.

Independent variable: electricity price for industrial users

Electricity Residential Price			Electricity Residential Price			Electricity Transportation Price			Coal Lignite			Coal Anthracite			Coal Bituminous		
intercept	slope	R-squared	intercept	slope	R-squared	intercept	slope	R-squared	intercept	slope	R-squared	intercept	slope	R-squared	intercept	slope	R-squared
1.01	0.83	0.92	1.01	0.83	0.92	-0.63	1.37	0.93	-3.89	1.24	0.84	-1.94	0.98	0.58	-4.37	1.75	0.95

Independent variable: bituminous coal price

Electricity Residential Price			Electricity Residential Price			Electricity Industrial Price			Electricity Transportation Price			Coal Lignite			Coal Anthracite		
intercept	slope	R-squared	intercept	slope	R-squared	intercept	slope	R-squared	intercept	slope	R-squared	intercept	slope	R-squared	intercept	slope	R-squared
3.09	0.45	0.88	3.09	0.45	0.88	2.51	0.54	0.95	2.81	0.76	0.92	-0.79	0.70	0.87	0.53	0.52	0.54

Source: calculations based on EIA data.

Note: relationship to other models

There are two key interactions with other models, mostly occurring in one equation. The demand for feedstocks to generate electricity depends on the electricity price, which is an output of the electricity model. Coal and biomass for electricity use are assumed to be perfect substitutes at the margin. Any increase in biomass used for electricity generation comes at the expense of coal. These two interactions are apparent in the equation representing the demand for coal and biomass to use in electricity generation.

Variables in the Coal module

NAME	DESCRIPTION	SOURCE
ENCBDELS	Aggregate coal and biomass demand, trillion btu	Calculated
ENBMDELS	Electricity sector demand for biomass, trillion btu	EIA historical data, AEO 2011
ENCLDELS	Electricity sector demand for coal, trillion btu	EIA historical data, AEO 2011
ENCLDIND	Industrial demand for coal, trillion btu	EIA historical data, AEO 2011
ENCLDNEX	Net exports of coal, trillion btu	EIA historical data, AEO 2011
ENCLDOTH	Other demand for coal, trillion btu	EIA historical data, AEO 2011
ENCLDSTK	Ending stocks of coal, trillion btu	EIA historical data, AEO 2011
ENCLPBIT	Bituminous coal price, $/million btu	EIA historical data, AEO 2011 from 2008
ENCLPBIT_S	Supply inducing bituminous coal price, $/million btu	Calculated
ENCLSPRD	Coal production, trillion btu	EIA historical data, AEO 2011
ENELPIND_S	Supply inducing electricity price, $/million btu	Calculated
ENELPMAN_BM	Mandate cost for electricity produced from biomass, $/million btu	Calculated
GDP_RW	GDP for rest of world	ERS
PPI	Producer price index (1986=Base Year)	FAPRI-MU

Coal module equations

```
log(ENCBDELS) = zENCBDELS_00 + zENCBDELS_P0 * log(
      (ENELPIND_S/(ENCLPBIT+(ENELPMAN_BM)*(ENBMDELS/ENCBDELS))
        + 2*lag1(ENELPIND_S/(ENCLPBIT+(ENELPMAN_BM)*(ENBMDELS/ENCBDELS)))
        +   lag2(ENELPIND_S/(ENCLPBIT+(ENELPMAN_BM)*(ENBMDELS/ENCBDELS)))
        +   lag3(ENELPIND_S/(ENCLPBIT+(ENELPMAN_BM)*(ENBMDELS/ENCBDELS))))/5
      )
      + zENCBDELS_TR*log(ztime-1970) + zENCBDELS_L1*log(lag1(ENCBDELS))

ENCLDELS = ENCBDELS - ENBMDELS

log(ENCLSPRD)= zENCLSPRD_00 + zENCLSPRD_PP * log((ENCLPBIT_S /PPI)
        +2*lag1(ENCLPBIT_S/PPI)+lag2(ENCLPBIT_S /PPI))
      + zENCLSPRD_TR * (ztime-2009)
      + zENCLSPRD_L1 * log(lag1(ENCLSPRD))

log(ENCLDIND) = zENCLDIND_00 + zENCLDIND_P0 * log(ENCLPBIT/PPI)
      + zENCLDIND_TR * (ztime-2009)
      + zENCLDIND_L1 * log(lag1(ENCLDIND))

log(ENCLDNEX) = zENCLDNEX_00 + zENCLDNEX_PP * log((ENCLPBIT/PPI))
      + zENCLDNEX_YY * log(GDP_RW)
      + zENCLDNEX_TR * (ztime-2009)
      + zENCLDNEX_L1 * log(lag1(ENCLDNEX))

log(ENCLDSTK) = zENCLDSTK_00 + zENCLDSTK_PP * log((ENCLPBIT_S/PPI))
      + zENCLDSTK_QQ * log(ENCLSPRD)
      + zENCLDSTK_TR * (ztime-2009)

ENCLSPRD +lag1(ENCLDSTK) = ENCLDNEX +ENCLDIND +ENCLDELS +ENCLDOTH +ENCLDSTK

ENCLPBIT_S = ENCLPBIT
```

Coal module parameters

Table 5. Parameter estimates: Coal sector

NAME	VALUE
zENCBDELS_00	4.34

zENCBDELS_P0*	0.40
zENCBDELS_TR	0.19
zENCBDELS_L1*	0.40
zENCLSPRD_00	0.57
zENCLSPRD_PP*	0.33
zENCLSPRD_TR	0.01
zENCLSPRD_L1*	0.90
zENCLDIND_00	4.97
zENCLDIND_P0	-0.29
zENCLDIND_TR	-0.02
zENCLDIND_L1	0.32
zENCLDNEX_00	-10.56
zENCLDNEX_PP*	-1.00
zENCLDNEX_YY*	1.25
zENCLDNEX_TR	-0.07
zENCLDNEX_L1	0.58
zENCLDSTK_00	8.12
zENCLDSTK_PP*	-1.00
zENCLDSTK_QQ*	0.00
zENCLDSTK_TR	-0.02

*: Assumed value

Source: own calculations

Electricity market

Table 6. Electricity quantities and shares

	1969-2009		1970-79		1980-89		1990-2009	
				Trillion btu				
Electricity Supply Variables								
Coal Fired Generation	4973	50%	2968	45%	4618	54%	6282	50%
Distillate Fired Generation	547	5%	1000	15%	523	6%	336	3%
Natural Gas Fired Generation	1562	16%	1132	17%	1019	12%	2069	16%
Nuclear Generation	1621	16%	497	8%	1275	15%	2435	19%
Hydroelectric Generation	950	10%	940	14%	970	11%	948	8%
Biomass Fired Generation	95	1%	1	0%	15	0%	188	1%
Geothermal Generation	34	0%	8	0%	29	0%	51	0%
Solar/Photovoltaic Generation	1	0%	.	.	0	0%	2	0%
Wind Generation	36	0%	.	.	1	0%	49	0%
Other Generation	71	1%	.	.	40	0%	73	1%
Total Generation	9844	99%	6547	99%	8454	98%	12433	99%
Imports	110	1%	48	1%	129	2%	136	1%
Total Supply	9954		6595		8584		12569	
Electricity Demand Variables								
Industrial Consumption	2999	32%	2406	40%	2848	36%	3425	29%
Residential Consumption	3130	34%	1999	33%	2717	34%	3986	34%
Commercial Consumption	2807	30%	1561	26%	2317	29%	3759	32%
Transportation Consumption	16	0%	10	0%	14	0%	20	0%
Direct Use within Electricity Generation Sector	520	6%	.	.	371	5%	528	4%
Total Consumption	9218	100%	5976	100%	7932	100%	11718	100%
Exports	30	0%	10	0%	19	0%	46	0%
Total Demand (for Electricity-Generation)	9248		5986		7951		11765	

Source: EIA data

In Table 6, we see further evidence of the strong link between the coal and electricity sectors. As the electric power sector was the dominant source of demand for coal, coal-fired generation is the dominant source of electricity in the US. Coal and nuclear generation (around two-thirds of total electricity generated) make up the steady, or "base-load", supply. Electricity generation from natural gas, and to a decreasing extent, distillate fuels make up the "peak-load" supply. In other words, they can be brought online quickly in periods where base-load supply can't keep up with demand, and they can be taken offline quickly when demand stabilizes.

Hydroelectric generation has remained fairly steady over the period. However, non-hydro renewables (biomass, geothermal, solar/pv, wind, other) make up a small but increasing source of electricity. Wind and biomass sources are expected to make the most rapid gains in near term (AEO 2011).

Electricity consumption in the industrial, residential, commercial, and direct use categories increased steadily over the period. The shares of consumption have remained pretty evenly split among the three sectors. Consumption within the transportation sector remained vanishingly small throughout the period.

Variables in the Electricity module

NAME	DESCRIPTION	SOURCE
ENCLDELS		
ENCLPBIT_S	Supply inducing bituminous coal price, $/million btu	Calculated
ENELDCOM	Commercial demand for electricity, trillion btu	EIA historical data, AEO 2011
ENELDEXP	Export demand for electricity, trillion btu	EIA historical data, AEO 2011
ENELDIND	Industrial demand for electricity, trillion btu	EIA historical data, AEO 2011
ENELDOTH	Other demand for electricity, trillion btu	EIA historical data, AEO 2011
ENELDRES	Residential demand for electricity, trillion btu	EIA historical data, AEO 2011
ENELDTRN	Transportation demand for electricity, trillion btu	EIA historical data, AEO 2011

ENELPCOM	Commercial electricity price, $/million btu	EIA historical data, AEO 2011
ENELPIND	Industrial electricity price, $/million btu	EIA historical data, AEO 2011
ENELPIND_S	Supply inducing electricity price, $/million btu	Calculated
ENELPMAN	Overall mandate price, $/million btu	Calculated
ENELPMCOSTP	Mandate cost per unit, $/million btu	Calculated
ENELPMCOSTT	Total mandate cost, billion $	Calculated
ENELPRES	Residential electricity price , $/million btu	EIA historical data, AEO 2011
ENELPSWN	Price for wind generated electricity, $/million btu	EERE
ENELPTRN	Transportation electricity price, $/million btu	EIA historical data, AEO 2011
ENELSACAP	Cumulative solar capacity, total, Megawatts	Sherwood, 2011 "US Solar Market Trends 2010"
ENELSCSD_GRS	Distributed solar gross installed cost, $/watt	Barbose et al. 2010. "Tracking Sun II: The Installed Cost of Photovoltaics in the US from 1998-2009."
ENELSCSD_NET	Distributed solar net installed cost, $/watt	Barbose et al. 2010. "Tracking Sun II: The Installed Cost of Photovoltaics in the US from 1998-2009."
ENELSCSD_STS	Distributed solar State/Utility cash incentive, $/watt	Barbose et al. 2010. "Tracking Sun II: The Installed Cost of Photovoltaics in the US from 1998-2009."
ENELSCSN_GRS	Centralized solar gross installed cost, $/watt	Barbose et al. 2010. "Tracking Sun II: The Installed Cost of Photovoltaics in the US from 1998-2009."
ENELSCSN_NET	Centralized solar net installed cost, $/watt	Barbose et al. 2010. "Tracking Sun II: The Installed Cost of Photovoltaics in the US from 1998-2009."
ENELSCSN_STS	Centralized solar State/Utility cash incentive, $/watt	Barbose et al. 2010. "Tracking Sun II: The Installed Cost of Photovoltaics in the US from 1998-2009."
ENELSCWN_GRS	Wind power gross installed cost, $/watt	EERE, 2011
ENELSCWN_NET	Wind power net installed cost, $/watt	EERE, 2011
ENELSDCAP	Cumulative solar capacity, distributed, Megawatts	Barbose et al. 2010. "Tracking Sun II: The Installed Cost of Photovoltaics in the US from 1998-2009." ; EIA historical shares
ENELSIMP	Electricity imports, trillion btu	EIA historical data, AEO 2011
ENELSNCAP	Cumulative solar capacity, centralized, Megawatts	Barbose et al. 2010. "Tracking Sun II: The Installed Cost of Photovoltaics in the US from 1998-2009." ; EIA historical shares
ENELSPACP_FED	Federal Alternative Compliance Payment, $/million btu	DSIRE, 2011
ENELSPACP_STATE	State Alternative Compliance Payment, $/million btu	DSIRE, 2011
ENELSPBM	Electricity generated from biomass, trillion btu	EIA historical data, AEO 2011
ENELSPCL	Electricity generated from coal, trillion btu	EIA historical data, AEO 2011
ENELSPCMBM_FED	Federal credit multiplier for biomass	DSIRE, 2011
ENELSPCMBM_STATE	State credit multiplier for biomass	DSIRE, 2011
ENELSPCMRO_FED	Federal credit multiplier for other renewable	DSIRE, 2011
ENELSPCMRO_STATE	State credit multiplier for other renewable	DSIRE, 2011
ENELSPCMSD_FED	Federal credit multiplier for distributed solar	DSIRE, 2011
ENELSPCMSD_STATE	State credit multiplier for distributed solar	DSIRE, 2011
ENELSPCMSN_FED	Federal credit multiplier for centralized solar	DSIRE, 2011
ENELSPCMSN_STATE	State credit multiplier for centralized solar	DSIRE, 2011
ENELSPCMWN_FED	Federal credit multiplier for wind	DSIRE, 2011
ENELSPCMWN_STATE	State credit multiplier for wind	DSIRE, 2011
ENELSPCMWT_FED	Federal credit multiplier for hydroelectric	DSIRE, 2011
ENELSPCMWT_STATE	State credit multiplier for hydroelectric	DSIRE, 2011
ENELSPDF	Electricity generated from distillate fuels	EIA historical data, AEO 2011
ENELSPMN_FED	Share of federal RPS for total renewable	Calculated
ENELSPMN_FRQ	Federal RPS requirement, trillion btu	DSIRE, 2011
ENELSPMN_SRQ	State RPS requirement, trillion btu	Calculated
ENELSPMN_STATE	Share of state RPS for total renewable	DSIRE, 2011
ENELSPNG	Electricity generated from natural gas, trillion btu	EIA historical data, AEO 2011
ENELSPNU	Electricity generated from nuclear power, trillion btu	EIA historical data, AEO 2011
ENELSPOT	Electricity generated from other sources, trillion btu	EIA historical data, AEO 2011
ENELSPRN	Electricity generated from all renewable sources, trillion btu	EIA historical data, AEO 2011
ENELSPRO	Electricity generated from other renewable sources, trillion btu	EIA historical data, AEO 2011
ENELSPSD	Electricity generated from distributed solar, trillion btu	EIA historical data, AEO 2011
ENELSPSN	Electricity generated from centralized solar, trillion btu	EIA historical data, AEO 2011
ENELSPWN	Electricity generated from wind energy, trillion btu	EIA historical data, AEO 2011
ENELSPWT	Electricity generated from hydro, trillion btu	EIA historical data, AEO 2011
ENELSSBB_RATE	Federal grant rate as percent of costs	DSIRE, 2011
ENELSSBF_TOTAL	Tax credits for renewable energy excluding hydro , billions of $	DSIRE, 2011
ENELSSBF_UNIT	Tax credits for renewable energy excluding hydro, $/watt	DSIRE, 2011
ENELWNCAP	Cumulative wind power capacity, Megawatts	EERE, 2011
ENNGDELS		

PPI	Producer price index (1986=Base Year)	FAPRI-MU
ZCE92W	Real consumer expenditures, million $	FAPRI-MU

Electricity module equations

```
log(ENELDIND) = zENELDIND_00  + zENELDIND_PE *  log(ENELPIND/PPI)
      + zENELDIND_YY * log(ZCE92W)
      + zENELDIND_TR * log(ztime - 1970)
      + zENELDIND_YT *  log(ZCE92W) * log(ztime - 1970)

log(ENELDRES/POPTOTW) = zENELDRES_00
      + zENELDRES_PE *  log(ENELPRES*100/PCIUW)
      + zENELDRES_YY * log(ZCE92W/POPTOTW)
      + zENELDRES_TR * log(ztime - 1970)

log(ENELDCOM) = zENELDCOM_00  + zENELDCOM_PE *  log(ENELPCOM/PPI)
      + zENELDCOM_YY * log(ZCE92W)
      + zENELDCOM_L1 * log(lag1(ENELDCOM))
      + zENELDCOM_TR * log(ztime - 1970)
      + zENELDCOM_YT *  log(ZCE92W) * log(ztime - 1970)

ENELPIND = ENELPIND_S + ENELPMCOSTP

ENELPRES = zENELPRES_00 + zENELPRES_PE * ENELPIND

ENELPCOM = zENELPCOM_00 + zENELPCOM_PE * ENELPIND

ENELSPCL + ENELSPNG + ENELSPDF + ENELSPNU + ENELSPRN + ENELSPWT + ENELSPBM
      + ENELSPOT + ENELSIMP + ENELSPSD
      = ENELDEXP + ENELDIND + ENELDRES + ENELDCOM + ENELDTRN + ENELDOTH

log(ENELSPNU) = zENELSPNU_00 + zENELSPNU_PP * log(
        ((ENELPIND_S/PPI)+2*lag1(ENELPIND_S/PPI)+lag2(ENELPIND_S/PPI))/4)
      + zENELSPNU_TR * (ztime-2009) + zENELSPNU_L1 * log(lag(ENELSPNU))

(ENELSPNG/ENNGDELS - lag(ENELSPNG/ENNGDELS))=
      zENELSPNG_00 + zENELSPNG_TR * log(ztime-1970)

(ENELSPCL/ENCLDELS-lag1(ENELSPCL/ENCLDELS))=
      zENELSPCL_00 + zENELSPCL_TR * log(ztime-1970)


ENELSPWT = exp(zENELSPWT_00 + zENELSPWT_PP * log(
        (((ENELPIND_S+ENELPMAN_WT)/PPI)
            +2*lag1((ENELPIND_S+ENELPMAN_WT)/PPI)
            +lag2((ENELPIND_S+ENELPMAN_WT)/PPI))/4
        )
      + zENELSPWT_TR * (ztime-2009)
      + zENELSPWT_L1 * log(lag(ENELSPWT))
      )

ENELSPWT_SFAKE = exp(zENELSPWT_00 + zENELSPWT_PP * log(
        (((ENELPIND_S+ENELPMAN_WT_SFAKE)/PPI)
            +2*lag1((ENELPIND_S+ENELPMAN_WT)/PPI)
            +lag2((ENELPIND_S+ENELPMAN_WT)/PPI))/4
        )
      + zENELSPWT_TR * (ztime-2009) + zENELSPWT_L1 * log(lag(ENELSPWT))
```

```
      )


ENELSPRO = exp( zENELSPRO_00 + zENELSPRO_PP * log(
        (((ENELPIND_S+ENELPMAN_RO)/PPI)
            +2*lag1((ENELPIND_S+ENELPMAN_RO)/PPI)
            +lag2((ENELPIND_S+ENELPMAN_RO)/PPI))/4
        )
      + zENELSPRO_TR * (ztime-2009) + zENELSPRO_L1 * log(lag(ENELSPRO))
      )


ENELSPRO_FFAKE = exp(zENELSPRO_00 + zENELSPRO_PP * log(
        (((ENELPIND_S+ENELPMAN_RO_FFAKE)/PPI)
            +2*lag1((ENELPIND_S+ENELPMAN_RO)/PPI)
            +lag2((ENELPIND_S+ENELPMAN_RO)/PPI))/4
        )
      + zENELSPRO_TR * (ztime-2009) + zENELSPRO_L1 * log(lag(ENELSPRO))
      )


ENELSPRN = ENELSPRO + ENELSPSN + ENELSPWN

log(ENELPSWN) = zENELPSWN_00 + zENELPSWN_TR * log(ztime-1970)
      + zENELPSWN_P0 * log((ENELPIND_S+ENELPMAN_WN)
      + lag(ENELPIND_S+ENELPMAN_WN))

(ENELWNCAP - 0.95*lag(ENELWNCAP)) = exp(zENELWNCAP_00
      + zENELWNCAP_R0 * log( ENELPSWN/ ENELSCWN_NET )
      + zENELWNCAP_R1 * log(lag((ENELPIND_S+ENELPMAN_WN) / ENELSCWN_NET ))) )

log(ENELSPWN/ENELWNCAP) = zENELSPWN_00 + zENELSPWN_R1 * log( ENELPSWN / PPI )

(ENELSNCAP - 0.95*lag(ENELSNCAP)) = exp(mzENELSNCAP_00
      + zENELSNCAP_R0 * log( (ENELPIND_S+ENELPMAN_SN) / ENELSCSN_NET ) )

log(ENELSPSN/ENELSNCAP) = zENELSPSN_00
      + zENELSPSN_R1 * log( (ENELPIND+ENELPMAN_SN) / PPI )

(ENELSDCAP - 0.95*lag(ENELSDCAP))= exp(zENELSDCAP_00
      + zENELSDCAP_R0 * log( (ENELPIND_S+ENELPMAN_SD) / ENELSCSD_NET ) )

log(ENELSPSD/ENELSDCAP)= zENELSPSD_00
      + zENELSPSD_R1 * log( (ENELPIND+ENELPMAN_SD) / PPI )

log(ENELSCSN_GRS)=zENELSCSN_GRS_00 + zENELSCSN_GRS_TR*log(ztime-1970)
      + zENELSCSN_GRS_PI * log(PPI)

ENELSCSN_NET =  ENELSCSN_GRS*(1-ENELSSBB_RATE) - ENELSCSN_STS - ENELSSBF_UNIT

log(ENELSCSD_GRS) = zENELSCSD_GRS_00 + zENELSCSD_GRS_TR*log(ztime-1970)
      + zENELSCSD_GRS_PI * log(PPI)

ENELSCSD_NET =  ENELSCSD_GRS*(1-ENELSSBB_RATE) - ENELSCSD_STS - ENELSSBF_UNIT

log(ENELSCWN_GRS)= zENELSCWN_GRS_00 + zENELSCWN_GRS_TR*log(ztime-1970)
      + zENELSCWN_GRS_PI * log(PPI)
```

```
ENELSCWN_NET =  ENELSCWN_GRS*(1-ENELSSBB_RATE) - ENELSSBF_UNIT


ENELSPMN_SRQ = (ENELSPMN_STATE/100) * (ENELSPCL+ENELSPNG+ENELSPDF+ENELSPNU
      +ENELSPWT+ENELSPRN+ENELSPBM+ENELSPOT+ENELSPSD)

0= ((ENELPMAN_SFAKE)**2+((ENELSPRO*ENELSPCMRO_STATE+ENELSPSN*ENELSPCMSN_STATE
      +ENELSPSD*ENELSPCMSD_STATE+ENELSPWT_SFAKE*ENELSPCMWT_STATE
      +ENELSPWN*ENELSPCMWN_STATE+ENELSPBM*ENELSPCMBM_STATE -ENELSPMN_SRQ))**2
      + 1E-4 )**(1/2)
   - (ENELPMAN_SFAKE+( ENELSPRO*ENELSPCMRO_STATE+ENELSPSN*ENELSPCMSN_STATE
      +ENELSPSD*ENELSPCMSD_STATE+ENELSPWT_SFAKE*ENELSPCMWT_STATE
      +ENELSPWN*ENELSPCMWN_STATE+ENELSPBM*ENELSPCMBM_STATE -ENELSPMN_SRQ))

ENELSPMN_FRQ = (ENELSPMN_FED/100) *(ENELSPCL+ENELSPNG+ENELSPDF+ENELSPNU
      +ENELSPWT+ENELSPRN+ENELSPBM+ENELSPOT+ENELSPSD)

0=  ((ENELPMAN_FFAKE)**2+((ENELSPRO_FFAKE*ENELSPCMRO_FED
      +ENELSPSN*ENELSPCMSN_FED+ENELSPSD*ENELSPCMSD_FED
      +ENELSPWT*ENELSPCMWT_FED+ENELSPWN*ENELSPCMWN_FED
      +ENELSPBM*ENELSPCMBM_FED -ENELSPMN_FRQ))**2 + 1E-4 )**(1/2)
  - (ENELPMAN_FFAKE+( ENELSPRO_FFAKE*ENELSPCMRO_FED+ENELSPSN*ENELSPCMSN_FED
      +ENELSPSD*ENELSPCMSD_FED+ENELSPWT*ENELSPCMWT_FED
      +ENELSPWN*ENELSPCMWN_FED+ENELSPBM*ENELSPCMBM_FED -ENELSPMN_FRQ))

ENELPMAN=   MAX(
      MIN ( ENELSPACP_STATE, MAX(ENELPMAN_SFAKE,0)) ,
      MIN ( ENELSPACP_FED, MAX(ENELPMAN_FFAKE,0)) )

ENELPMAN_BM = MAX(
      MIN(ENELSPACP_STATE, MAX(ENELPMAN_SFAKE,0)) *ENELSPCMBM_STATE,
      MIN ( ENELSPACP_FED, MAX(ENELPMAN_FFAKE,0)) *ENELSPCMBM_FED)

ENELPMAN_WN = MAX(
      MIN(ENELSPACP_STATE, MAX(ENELPMAN_SFAKE,0)) *ENELSPCMWN_STATE,
      MIN ( ENELSPACP_FED, MAX(ENELPMAN_FFAKE,0)) *ENELSPCMWN_FED)

ENELPMAN_SN = MAX(
      MIN(ENELSPACP_STATE, MAX(ENELPMAN_SFAKE,0)) *ENELSPCMSN_STATE,
      MIN ( ENELSPACP_FED, MAX(ENELPMAN_FFAKE,0)) *ENELSPCMSN_FED

ENELPMAN_SD = MAX(
      MIN(ENELSPACP_STATE, MAX(ENELPMAN_SFAKE,0)) *ENELSPCMSD_STATE,
      MIN ( ENELSPACP_FED, MAX(ENELPMAN_FFAKE,0)) *ENELSPCMSD_FED)

ENELPMAN_WT = MAX(
      MIN(ENELSPACP_STATE, MAX(ENELPMAN_SFAKE,0)) *ENELSPCMWT_STATE,
      MIN ( ENELSPACP_FED, MAX(ENELPMAN_FFAKE,0)) *ENELSPCMWT_FED)

ENELPMAN_RO = MAX(
      MIN(ENELSPACP_STATE, MAX(ENELPMAN_SFAKE,0)) *ENELSPCMRO_STATE,
      MIN ( ENELSPACP_FED, MAX(ENELPMAN_FFAKE,0)) *ENELSPCMRO_FED)

ENELPMAN_WT_SFAKE = ENELPMAN_SFAKE *ENELSPCMWT_STATE

ENELPMAN_RO_FFAKE = ENELPMAN_FFAKE *ENELSPCMRO_FED
```

```
ENELPMCOSTT = MAX(
      ENELSPMN_SRQ * MIN ( ENELSPACP_STATE, MAX(ENELPMAN_SFAKE,0)) ,
      ENELSPMN_FRQ * MIN ( ENELSPACP_FED, MAX(ENELPMAN_FFAKE,0)) )

ENELPMCOSTP =  ENELPMCOSTT /
      (ENELSPCL+ENELSPNG+ENELSPDF+ENELSPNU+ENELSPWT
            +ENELSPRN+ENELSPBM+ENELSPOT+ENELSPSD)
```

Electricity module parameters

Table 7. Parameter estimates: Electricity sector

NAME	VALUE	NAME	VALUE
zENELDIND_00	-3.236	zENELSPWT_00	2.887
zENELDIND_PE	-0.623	zENELSPWT_PP*	0.050
zENELDIND_YY	1.565	zENELSPWT_TR	-0.001
zENELDIND_TR	3.553	zENELSPWT_L1	0.559
zENELDIND_YT	-0.433	zENELSPRO_00	0.206
zENELDRES_00	1.520	zENELSPRO_PP	0.206
zENELDRES_PE	-0.128	zENELSPRO_TR	0.001
zENELDRES_YY	0.387	zENELSPRO_L1	0.825
zENELDRES_TR	0.097	zENELPSWN_00	64.798
zENELDCOM_00	-1.045	zENELPSWN_TR	-19.838
zENELDCOM_PE	-0.154	zENELWNCAP_00	8.714
zENELDCOM_YY	0.701	zENELWNCAP_R0*	0.010
zENELDCOM_L1	0.405	zENELWNCAP_R1	-0.218
zENELDCOM_TR	1.031	zENELSPWN_00	-4.996
zENELDCOM_YT	-0.108	zENELSPWN_R1*	0.010
zENELSPNU_00	-0.551	zENELSNCAP_00	0.284
zENELSPNU_PP	0.287	zENELSNCAP_R0	1.683
zENELSPNU_TR	0.001	zENELSPSN_00	-1.790
zENELSPNU_L1	0.986	zENELSPSN_R1*	0.010
zENELSPNG_00	-0.004	zENELSDCAP_00	-2.615
zENELSPNG_TR	0.003	zENELSDCAP_R0	5.219
zENELSPCL_00	-0.005	zENELSPSD_00	-1.790
zENELSPCL_TR	0.001	zENELSPSD_R1*	0.010
zENELPRES_00	0.025	zENELSCSN_GRS_00	5.633
zENELPRES_PE	1.651	zENELSCSN_GRS_TR	-1.140
zENELPCOM_00	1.508	zENELSCSN_GRS_PI	1.018
zENELPCOM_PE	1.436	zENELSCSD_GRS_00	7.123
		zENELSCSD_GRS_TR	-1.564
		zENELSCSD_GRS_PI	1.159

*: Assumed value

Source: own calculations

Model elasticities

Table 10. Estimated elasticities

Equation	With respect to	Short-run	Long-run
Electricity sector			
ENELDIND	ENELPIND	-0.62	
	ZCE92W	1.57	
ENELDRES	ENELPRES	-0.13	
	ZCE92W	0.39	
ENELDCOM	ENELPCOM	-0.15	
	ZCE92W	0.70	
ENELSPNU	ENELPIND	0.07	19.98
ENELSPWT	ENELPIND	0.01	0.11
ENLESPRO	ENELPIND	0.05	1.18
ENELSPWN	ENELPSWN	0.01	
ENELSPSN	ENELPIND	0.01	
ENELSPSD	ENELPIND	0.01	
ENELPRES	ENELPIND	0.99	
ENELPCOM	ENELPIND	0.92	
Natural gas sector			
ENNGDRES	ENNGPRES	-0.13	-0.18
	ENELPRES	0.13	0.18
	ZCE92W	0.1*	0.13
ENNGDIND	ENNGPIND	-0.13	-1.07
	ENELPIND	0.13	1.07
	ZCE92W	0.08	0.68
ENNGDCOM	ENNGPCOM	-0.16	-0.44
	ENELPCOM	0.16	0.44
	ZCE92W	0.21	0.58
ENNGDELS	ENNGPELS	-0.06	-0.46
	ENCLPBIT	0.06	0.46
	ZCE92W	0.24	1.73
ENNGDEXP	ENNGPWHD	-0.03	-0.12
ENNGSPRD	ENNGPWHD	0.25*	2.5*
ENNGSIMP	ENNGPWHD	0.21*	1.61
ENNGPIND	ENNGPWHD	0.83	
ENNGPRES	ENNGPWHD	0.5	
ENNGPCOM	ENNGPWHD	0.62	
ENNGPELS	ENNGPWHD	0.93	
Coal sector			
ENCLSPRD	ENCLPBIT_S	0.33*	3.3*
ENCLDIND	ENCLPBIT	-0.29	-0.43
ENCLDNEX	ENCLPBIT	-1*	-2.38
	ZCE92W	1.25*	2.97
ENCLDSTK	ENCLPBIT	-1*	

*: Assumed value

Source: own calculations

Energy policy

Existing energy policies

State Renewable Portfolio Standards

Renewable Portfolio Standards exist in 29 states and the District of Columbia (Wiser et al., 2010). A key practically question is whether the existing state RPSs does or does not exceed a proposed federal RPS. Projections take into account existing RPS based on an existing compilation of these policies, "DSIRE" (EERE and NCSU, 2011). There are several steps, however.

First, state-level electricity sales data are from EIA Electric Power Monthly, State Historical Tables for 2009 (www.eia.gov/cneaf/electricity/epa/epa_sprdshts.html). These data are extrapolated forward using exponential growth trends. The jurisdictions with RPSs accounted for 65% of US electricity sales in 2000 and 64% in 2010, with 63% as the estimated share in 2020.

Second, state RPSs do not apply to all energy. DSIRE provides a share of load covered, which is used directly by taking the product of load covered and the state electricity sales. Moreover, some elements of the RPS apply only to some types of firms, with the most common distinction reported in DSIRE being between investor-owned utilities and others (municipalities and cooperatives). The share of sales from investor-owned utilities is taken from EIA data (EIA (www.eia.gov/cneaf/electricity/public/t01p01p1.html), but the national share is applied to all states.

The third complexity is that, in addition to type of utility, there are also complications in the tiered structure of most state RPSs, as reported in DSIRE. The tier reflects carve-outs or set-asides for particular sources of renewable energy relative to others. These tiers have played a role in the development of wind (EERE, 2011) and solar power (Barbose et al., 2010), but this particular special treatment relative to other renewables may not continue to be a driving factor at least for solar power (Wiser et al., 2010). DSIRE data suggest that eligibility is complicated. There are 80 types (e.g. applying to investor-owned or other utilities) and tiers of state RPSs in DSIRE (Table). Ocean is eligible for the fewest of these, only 30 out of 80, representing perhaps the number of land-locked states. Geothermal and hydro power is eligible for 38 and 40, respectively. Solar power, particularly photovoltaic that is distributed among end users or centralized photovoltaic, are eligible in over three-quarters of the cases. Concentrated solar power (CSP), wind, and biomass are eligible in somewhat fewer instances.

Table 8. Eligibility for 80 Types and Tiers of State RPSs.

Eligible feedstock	Cross-eligibility with other feedstock in same RPS type and tier								
	Wind	CSP	Photovoltaic		Biomass	Hydro	Geothermal	Landfill Gas	Ocean
			Distributed	Centralized					
Wind	**54**	44	49	47	47	37	37	47	30
CSP	44	**53**	53	53	43	33	35	43	27
Distributed PV	49	53	**64**	61	45	35	37	45	29
Centralized PV	47	53	61	**62**	46	36	37	46	30
Biomass	47	43	45	46	**51**	40	38	50	30
Hydro	37	33	35	36	40	**40**	31	39	23
Geothermal	37	35	37	37	38	31	**38**	38	27
Landfill Gas	47	43	45	46	50	39	38	**50**	30
Ocean	30	27	29	30	30	23	27	30	**30**

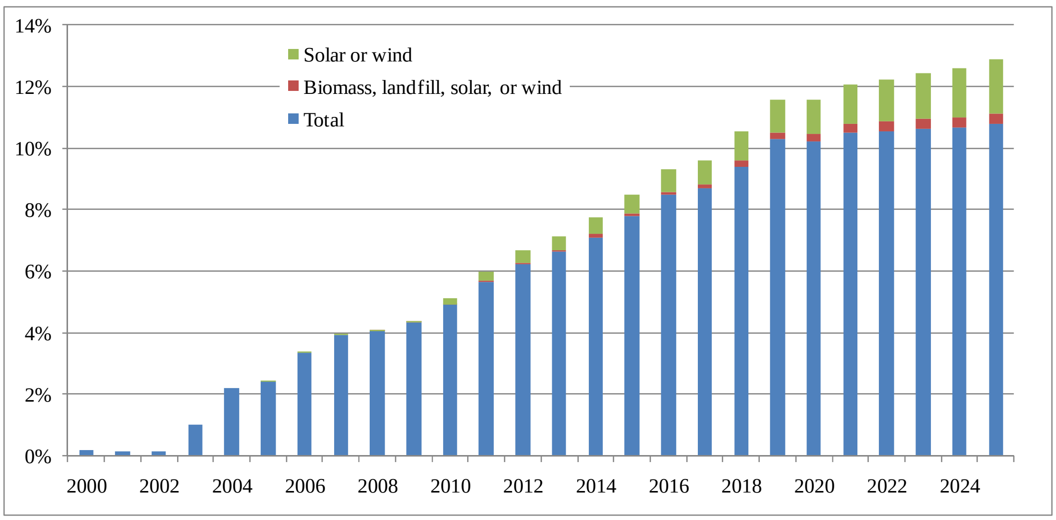
Source: calculations based on DSIRE data (EERE and NCSU).

The fourth step is combining DSIRE RPS data with EIA sales data. In many cases, this requires multiplying each state's use, the share of load covered, the share of sales according to each RPS type, and the RPS target for each year. In a few instances, state RPSs are stated in volume rather than share, so the volume is used directly. A key assumption is that the RPS is constant at the final target level after the target year. Without this assumption, state RPSs would fall to zero in the year after the target year. This product is calculated three times. In one case, the total is taken without regard to eligibility to estimate the overall RPS. The second keeps any RPS for which biomass, landfill gas, solar, or wind are eligible, but hydro, geothermal, and ocean are not eligible. The third sums up state RPSs for which wind or any solar are eligible, but not biomass, landfill gas, hydro, geothermal, or ocean. In all cases, the RPS is expressed as a percent of total US use.

Based on these calculations, the majority of the RPS by volume can be seen as having relatively easily-met eligibility requirements (Figure 2). There is a share with narrow eligibility requirements that applies to solar or wind power (or both), and an even small share that includes these two sources or biomass or landfill gas (or any combination of these sources). However, most of the state RPS by volume has broad eligibility requirements, according to these calculations.

We do not take into account the fact that renewable energy use often falls somewhat short of state RPS targets. The average difference between actual and targeted levels for 16 states between 1999 and 2006 ranged as low as 86% and as high as 100% (Wiser and Barbose, 2008, p 22). These data only report compliance, not the degree to which the target was exceeded, if at all. The likely reason for falling short is that the price of renewables hit an upper limit (the ACP, below).

Figure 2. State RPS Eligibility.



Source: EERE and NCSU (DSIRE) and EIA data, with calculations as described in the text.

The DSIRE data (accessed July 2011) are presumably more current than the data used for the reference case of EIA's analysis of HR2454 (EIA, 2009). Comparing those data nevertheless suggests a similar starting value in 2012 but a stronger growth in RPSs than the EIA reference case. For example, the reference case renewable energy appears to start at about 7-8% in 2012, passes 10% in 2020, and rises to 12-13% in 2030 (figure 14, p 24).

Credit multipliers for RPSs cause some renewables to generate extra Renewable Energy Certificates (REC). No special treatment would imply a credit multiplier of one, so one unit of energy generates one REC. A credit multiplier of two means that each unit of energy generates two RECs. (The credit multiplier treatment for renewable electricity is analogous to the equivalence value for biofuels that count towards the Renewable Fuel Standard.) DSIRE data indicate that credit multipliers are often dependent on additional criterion, such as when capacity is built or the size of the facility.

The DSIRE data suggest that solar power tends to be the focus of credit multipliers (Table). Of the 80 total combinations of type and tier of RPS in the states that have them, 10% give some form of credit multiplier greater than one for distributed photovoltaics, 6% for centralized photovoltaics, and 4% for concentrated solar power. Of the types and tiers for which distributed photovoltaics are eligible, 13% give a credit multiplier of greater than one to this source of power. Centralized photovoltaics receive a credit multiplier of more than one in 8% of the types and tiers for which they are eligible. For other renewable energies, the shares with credit multipliers are smaller.

Table 9. Share of State RPSs with a Credit Multiplier, by Renewable Energy Type.

Source	Share of RPS Types and Tiers		Average Credit Multiplier		
	Total	Eligible	Total	Eligible	>1
Wind	1%	2%	0.71	1.05	3.50
CSP	4%	6%	0.73	1.09	2.67
Distributed PV	10%	13%	0.96	1.20	2.61
Centralized PV	6%	8%	0.86	1.11	2.40
Biomass	1%	2%	0.65	1.02	2.00
Hydro	1%	3%	0.51	1.03	2.00
Geothermal	1%	3%	0.49	1.03	2.00
Landfill Gas	1%	2%	0.64	1.02	2.00
Ocean	1%	3%	0.39	1.03	2.00

Source: calculations based on EERE and NCSU (DSIRE).

The average credit multipliers range from 1.02 to 1.20 if calculated for all cases in which the renewable is eligible. The average of credit multipliers of one or greater (but not zero that indicates ineligibility) is highest for distributed photovoltaics. Other solar power generates about 1.1 RECs per unit of energy. For biomass, the average credit multiplier is 1.02. These averages are considerably higher in instances when a credit multiplier of more than one is granted. In those cases that biomass receives a bonus through a credit multiplier greater than one, the average value is 2.00. Hydro, geothermal, landfill gas, and ocean power all receive the same bonus, on average, in those cases that they are given a bonus. The average value for wind of those instances that it has a bonus is much higher, at 3.50. The average credit multipliers over all types and tiers take into account instances of ineligibility (zero credit multiplier). The average of all values is only one-half or less for such sources as water and geothermal, 0.65 for biomass, and higher, but still less than one, for solar and wind.

For the model, the averages of all values, including zeros, are used. The inclusion of zeros offsets somewhat the simplification of ignoring eligibility requirements. These values are rescaled, however, so that the new values average to one. Also, values are averaged over some categories to match the energy sources represented in the model. Thus, the credit multiplier for biomass is 0.93. It is higher for distributed solar (1.37), centralized or concentrated solar (1.23) and wind (1.01), but lower for hydro (0.73) and other sources (0.72). By using the average value for an overall state mandate, the relative ranking is respected in a general sense.

Alternative Compliance Payments (ACPs) gives electricity generating firms an option to pay a fixed amount per unit of RPS that they fail to meet in the event that costs of meeting the RPS get very high. Two important characteristics are that they are varied by renewable source and the ACP cost can be passed on to consumers through rate increases in most cases (Wiser et al., 2010, p 22-3). Calculations using DSIRE data suggest that the simple average of ACPs or fees for non-compliance – either of which would set an upper limit on the price of RECs – is $34.35 per million BTU. However, there are many unknowns, not least the potential that they vary by source. Some are adjusted over time, often for inflation, or vary by utility type. Moreover, while instances of no ACP in DSIRE imply no upper bound to the cost of mandate compliance, in reality some action might be taken if the cost does rise. Replacing zero values with $146.54 (equivalent to a high value but still less than the nearly $200 observed maximum), gives an average ACP of $91.85.

In the model data, the state RPSs are treated as a single sum that rises from 1% in 2003 to about 12% in 2021 and 13% in 2026. The ACP for state RPSs is assumed to be $91.85 in all years. The average state RPS credit multiplier after rescaling for all types and tiers is used in all years. We include the restrictions to eligibility only indirectly through the application of averages that include instances of a credit multiplier of zero. By treating the state RPSs as a single overall mandate, we also ignore other complications, such as requirements for in-state production of some renewables or application to new rather than existing renewable capacity (Wiser and Barbose, 2008, p 22). We also treat the RPS as tradable among states, which generally the case (Wiser et al., 2010, p 5, 29) even though the wide range of Renewable Electricity Certificate prices suggest that trade might not balance prices – although it is difficult given that these prices reflect the types and tiers of mandates, the additional rules on in-state requirements, and credit multipliers.

Historical REC price data do not provide much basis for an average as they vary at least somewhat by state, type of RPS, and tier, and these differences in definition are not readily communicated. We assume an average historical price of about $3 per million BTU.

Existing financial support

Federal support for energy through the tax code is summarized by the Pew Tax Expenditure Database (http://subsidyscope.org/tax_expenditures/db/group/1/?estimate=3). We use the US Treasury estimates for renewable energies tax expenditures to corporations. This includes estimates of the value of the Production Tax Credit (PTC) from 2001, when it is valued at $0.055 billion, to 2016, $1.490 billion. We also take the estimated values of the Advanced Energy Property Credit, the credit for business installation of qualified fuel cells and stationary micro turbine power plants, the credit for holding clean renewable energy bonds, and the Investment Tax Credit (ITC). Although inconsequential before 2006, the total value of these programs are expected to rise $1.655 billion in 2013 before tapering off.

We treat separately the US Treasury Grant. Bolinger et al. (2010) note that from October 2008 "…Section 1603 of the Recovery Act enables qualifying commercial renewable energy projects to choose between the Section 45 PTC, the Section 48 ITC, or a cash grant of equal value to the Section 48 ITC (i.e., 30% of the project's eligible basis in most cases)" (p 1). This suggests that it is a grant rather than a tax expenditure. We assume it is not included in Pew data. The US Treasury Grant program had awarded $2.6 billion by March 2010 (Bolinger et al., 2010, p 3), whereas Pew data report that the US Treasury estimates are lower over a longer period with the total cost of PTC and ITC was $0.700 billion in 2009 and $1.670 billion in 2010. As the grant is a popular choice, not a requirement, we would expect the total bill including tax credits over the period to exceed the $2.6 billion cited above if it included the grant. In the model, the 30% grant is treated as a 30% cost reduction for building facilities for the few years that it is in place.

State support for solar power generation are available for commercial and residential facilities (Barbose et al., 2010, p 32). This support is applied to centralized and end-user capacity costs, respectively.

These federal and state policies target building facilities, not generation from existing facilities. In the model, they are applied to capacity building for solar (centralized and end-user) and wind power. The final year of US Treasury data for federal tax expenditures is 2016. After the last year that a rate per unit of additional capacity can be calculated, 2012, the rate moves with total expenditure to 2016 and is constant after that. The US Treasury Grant program is assumed to expire at the end of 2012. For state support to solar power, the last year of data is 2009, more than a third below the peak values in the early 2000s, and is held constant at the given per-unit levels from that point.

New energy policies

Federal Carbon Tax on Electricity Feedstocks

The model can distinguish between the price of fossil fuels that suppliers receive and producers pay. A carbon tax on these feedstocks is represented as a wedge between these two prices, driving down the price of coal or natural gas that suppliers receive and driving up their prices to electricity producers.

The implication for the natural gas market is straightforward, with the wedge causing a reduction in the quantity of natural gas in the market. Electricity prices would rise, leading to higher demand for competing electricity feedstocks, namely renewables. For coal, the impact should be a similar reduction in quantities, with a shift to alternatives and in particular biomass, its nearest substitute.

Federal Renewable Portfolio Standard

A hypothetical federal Renewable Portfolio Standard is represented in the model. The starting value is 0%, as there is no federal RPS, but this target share from renewables can be increased for policy analysis. There is no estimation of energy efficiency savings as such (although the price elasticities of demand presumably include efficiency in electricity use), so a proposal like the RPS in the American Clean Energy and Security Act of 2009, or HR 2454, that includes an overall target for renewables and efficiency must be recast as a mandate for the share of renewables in total electricity generation.

The federal RPS is separate from the aggregation of state RPSs. The federal RPS has its own percent target and also its own credit multipliers. Either one can be binding overall but a complication is that, at least in principle, either one can be binding for any type of renewable feedstock. For example, if an hypothetical federal RPS disallows hydro power, but this source does count for many state RPSs, then the federal RPS could drive REC prices for all other sources of renewables, but a higher state RPS might then be met only by the sum of the RECs that also meet the federal RPS plus additional RPSs generated for state compliance from hydro power.

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