Productivity Commission

Electricity dispatch regimes

:vivideconomics

1 Introduction

This note discusses the electricity dispatch regimes in each of the countries analysed by the Productivity Commission in its 'Emission Reduction Policies and Carbon Prices in Key Economies' study and, based on this, surmises the likely emission reductions achieved from an increase in low-carbon power generation.

2 China

2.1 Dispatch policy

China traditionally organised its electricity dispatch by providing a similar number of hours per year (annual "operational hours") to each thermal unit regardless of its efficiency or fuel consumption costs. This dispatch practice meant that demand growth risk, and the system reserve needs, were proportionally shared by all thermal generation investment. In the event that grid load fell due to lower demand, the regime required all grid-connected thermal generating units to evenly reduce their power output.

Correspondingly, this approach to dispatch would also imply that an increase in the supply of renewable energy would lead to a proportional reduction in operating hours for all thermal units.

In 2007 a programme of Energy Efficient and Environmental Friendly Power Generation Scheduling (ECPG scheduling) was issued. It created 7 classes of generation units based on their carbon intensity; the policy's intention is that units from a lower class are only brought on-line once the higher class is operating at full capacity. The different classes are:

- unadjustable renewable plants, including wind, solar, ocean power and hydro;
- adjustable hydro, biomass, geothermal and solid waste fired units;
- nuclear power plants;
- coal-fired cogeneration units and units for the comprehensive use of resources, including those using residual heat, residual gas, residual pressure, coal gangue, coal bed/coalmine methane;
- natural gas and coal gasification based combined cycle units;
- other coal-fired generation, including CHP units without heat load; and
- oil and oil products-fired generation.

Within each category, the intention is that units would be ranked according to their energy efficiency.

Trials started in five provinces in December 2007, with results expected by the middle of 2008. However, there is uncertainty as to how far the trials have progressed. Further uncertainty exists about the extent to which the ECPG has been rolled out beyond the trial provinces. According to Minchener (2010), 'no date has been announced for when the new ECPG scheduling rule will become effective nationwide'. Reports suggest that there have been challenges in introducing these scheduling arrangements as, in combination with the current structure of a one-part price tariff, it would imply closure of a large number of plants that would provide valuable peaking capacity (Howes and Dobes, 2010).

2.2 Potential values

As part of accrediting projects under the Clean Development Mechanism (CDM), grid emissions factors are calculated. Two different grid emission factors are computed:

— An 'operating margin' which attempts to reflect the displacement of power in the grid which is generated by fossil fuel power plants (e.g. how much less power will be produced by conventional power plants). This calculation includes all facilities apart from low-cost or must run facilities i.e. it approximates a weighted average carbon intensity of the fossil-based grid.

— A 'build margin' which attempts to assess what might not be built in the future as a result of the additional capacity by looking at the carbon intensity of the 20% most recently constructed plants.

Of these, our understanding from discussions with the Productivity Commission is that it is the operating margin figure which is closest to reflecting the counterfactual that it wishes to use for its assessment[1]. Moreover, on the basis of the discussion above regarding the approach to dispatch taken in China, the fact that the operating margin is calculated as a weighted average over all thermal sources (rather than assessing marginal sources) accurately reflects the way dispatch is organised in the country.

The table below provides the operating margins reported for each of the different grids in China over time. Calculations are based on the most recently available three years of data.

[1] In the CDM a weighted average of the two margins are calculated

Table 1 Operating margin intensities for the Chinese electricity sector, gCO_2/kWh

	October 2006	August 2007	December 2008	July 2009	December 2010
Northern Grid	1058.5	1120.8	1116.9	1006.9	991.4
Northeastern Grid	1198.3	1240.4	1256.1	1129.3	1110.9
Northwestern Grid	1032.9	1125.7	1122.5	1024.6	994.7
Eastern Grid	941.1	942.1	954.0	882.5	859.2
Central Grid	1252.6	1289.9	1278.3	1225.5	1087.1
Southern Grid	985.3	1011.9	1060.8	998.7	976.2
Simple Average	**1078.1**	**1121.8**	**1131.4**	**1044.6**	**1003.3**

Source: Michaelowa (2011)

In calculating this operating margin, emissions are divided by 'net electricity generated and delivered to the grid' (NDRC, 2009). The Productivity Commission may wish to consider making a further adjustment to these figures for transmission and distribution losses. The World Bank World Development Indicators database reports that, as a proportion of output, transmission and distribution losses in China were 6.7%, 6.3% and 6.0% from 2005 to 2007 respectively.

3 Germany

Four large producers dominate the German electricity market and between them control more than 80 per cent of total generation capacity. This has led to some concerns that the concept of least-cost merit order dispatch may hence not always hold in Germany. For instance, the European Commission inquiry into energy markets stated that:

> '*Significant generation capacity – most of it with low marginal costs – was retired in Germany despite slowly increasing demand. Also, certain plants with rather low marginal costs did not operate fully at all times*' (EC, 2007)

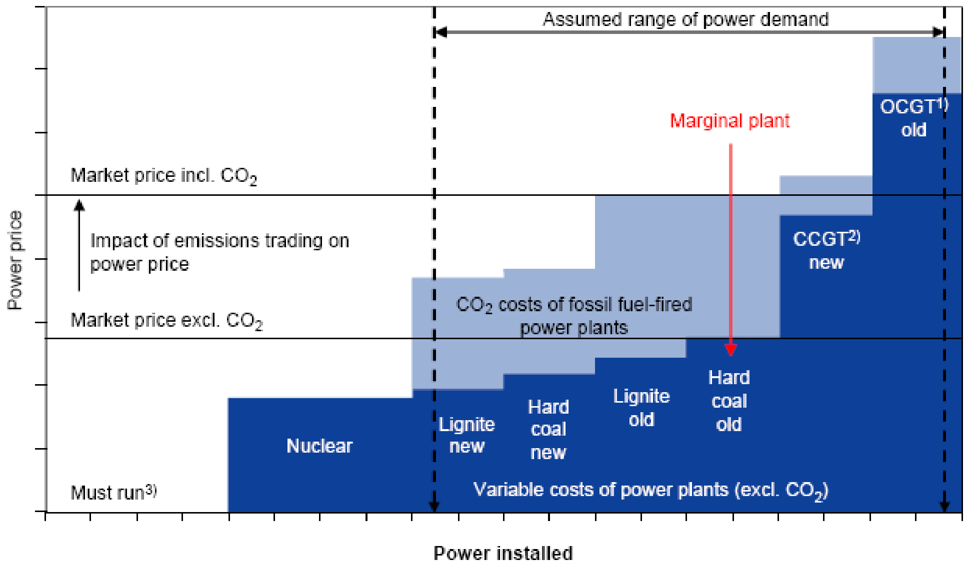
Nonetheless, most studies assume that the 'merit-order' approach to pricing is the best representation of the market and that coal or gas plants are typically the marginal plant. This is suggested by two separate studies.

Jansen and Wobben (2008) indicate that the marginal source varies between coal and gas, depending on the time of day:

> 'The price of coal is more frequently a factor in determining the price of electricity (i.e. constitutes the marginal plant) in off-peak hours than in peak hours, while the opposite holds true for gas'

This is further corroborated by data published by RWE, one of the major generating companies in Germany. In the merit-order curve published on its website, the marginal plant varies between new lignite, hard coal and CCGT gas power plants, depending on demand. The average marginal plant is given as 'old hard coal'. This is shown below in Figure 1.

Figure 1 **The marginal plant in Germany is typically either coal or gas**



Notes: 1) OCGT: Open-Cycle Gas Turbine, 2) CCGT:Combined-Cycle Gas Turbine, 3) must run: hydro, wind, CHP Source: RWE

Emission intensity data from RWE, and the German Federal Environment Agency (UBA) differ slightly, so we list both in table two.

Table 2 – Average carbon intensity of electricity supplied

Technology	Emission intensity (gCO_2/kWh)
RWE (2008)	
Lignite old	1200
Lignite new	950
Hard coal	900
Gas	500
Federal Environment Agency UBA (2009) – includes supply chain emissions	
Lignite	1101.45
Hard coal	956.89
Gas	438.02

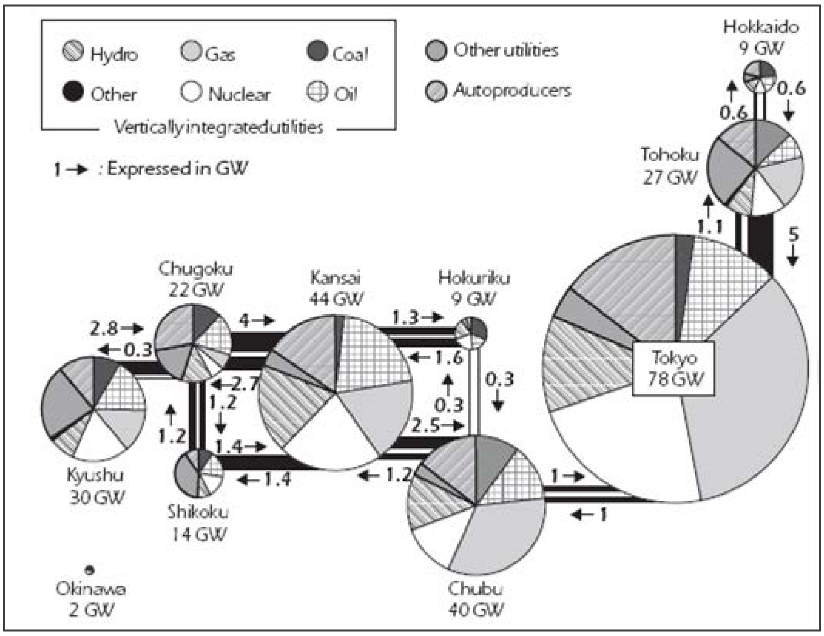
Sources: RWE, UBA

4 Japan

The Japanese grid is divided into two systems, the Western Grid operating at 60 Hz, and the Eastern Grid (covering Tokyo and the east of the country) operating at 50 Hz. They are connected by transformers capable of changing the frequencies, with a total capacity of 970 MW. However, in times of severe demand fluctuations or supply disruptions, this division has proven to be a bottleneck.

Generation is mostly in the hands of the 10 regional vertical-integrated power utilities, which act as regional monopolies and control approximately 85 per cent of the country's total installed capacity. Historically the regime required the ten integrated utilities to maintain self-sufficiency, leading to comparatively low inter-regional power trade. Transmission capacities are limited compared to capacity, but capacity is distributed widely throughout the country, as shown in figure 2.

Figure 2 Japanese generation and transmission capacity by fuel source

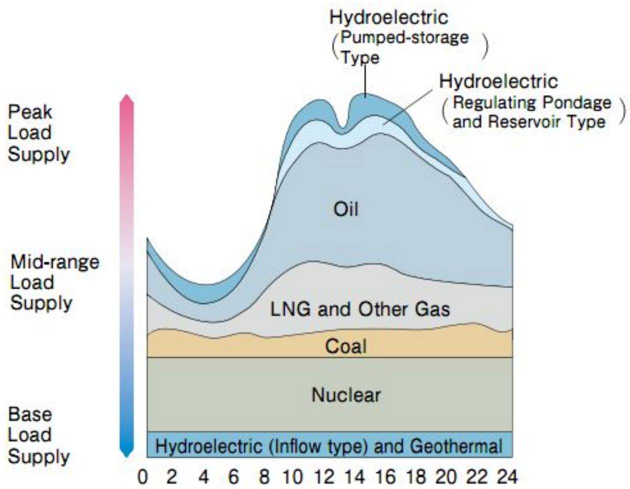


Source: IEA 2008

The structure of the Japanese power market, despite not being competitive, allows for profit-maximising behaviour of the regional vertically integrated utilities. Since retail-pricing is regulated, the minimisation of costs plays a large role in maximising profits. A least-cost dispatch order, which minimises costs, is hence a reasonable assumption.

Figure 3 shows a typical load duration curve in Japan. It is given as an example by the Federation of Electric Power Companies of Japan, and corroborated by load duration curves from the Electric Power System Council of Japan.

Figure 3 Load duration curve in Japan



Hydroelectric and nuclear power provides base load supply, while coal and LNG are major power sources for mid-range load supply. Oil-fired and pumped-storage hydroelectric power respond to peak demand fluctuation and contribute to consistent stable supply of electricity.

Source: FEPC 2010

This suggests that the marginal plant is likely to be oil. The IEA provides further corroboration stating that oil plants are 'relatively old and depreciated – as well as expensive to operate' (IEA 2008).

The emission intensity of oil-fired power is given in table 3 below. No unique number for the average emission intensity of oil-fired power plants in Japan was found. Instead, we assembled the emissions intensity of a sample of 16 Japanese oil-fired power stations, covering 26% of power production from oil in Japan and used emissions intensities for each of these plant reported by www.carma.org. The average emission intensity of this sample is 380.6 gCO_2/kWh, with a maximum of 436.8 gCO_2/kWh and a minimum of 308.8 gCO_2/kWh.

Pumped storage also provides output at times of peak demand. However, this uses off-peak (and hence low cost) electricity to pump water into a reservoir, from which it is released during peak demand. It does not 'generate' electricity in the classical sense. Given that it primarily acts as a storage technology, we attribute it with the average emissions intensity.

Table 3 Estimates of the emissions intensity of marginal electricity plants in Japan

Technology	Emissions intensity (gCO_2/kWh)
Oil-fired thermal	380.6 (2007)
Pumped storage (average grid intensity)	447.8 (2007)

Source: Data from CARMA (www.carma.org) and CAIT

The Productivity Commission may also wish to take account of transmission and distribution losses. The World Bank World Development Indicators database reports that, as a proportion of output, transmission and distribution losses in Japan were 4.6%, 4.6% and 4.5% from 2005 to 2007 respectively.

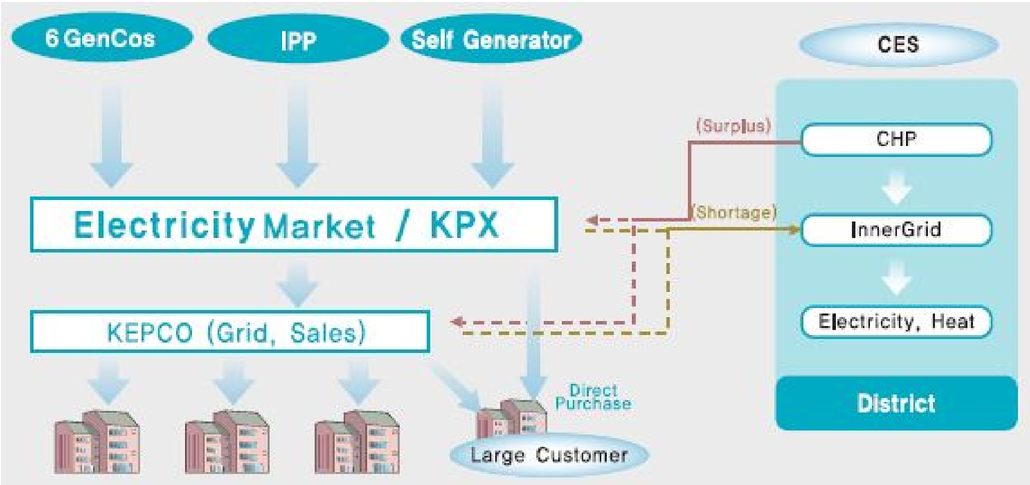
5 South Korea

The Korean power market was partially deregulated in 2001. This process led to the creation of six generation companies from the formerly sole utility, KEPCO (Korea Electric Power Corporation) and the establishment of a wholesale market. Besides the six large generation companies, another 288 independent power producers sell power to KEPCO in the wholesale market. KEPCO remains the sole wholesale buyer of electricity, with the exception of a few very large industrial customers.

Outside this structure, a number of Community Energy Suppliers (CES) produce power in CHP plants and sell it directly to their licensed areas. They are permitted to buy and sell power on the KPX whenever they experience a local shortage or surplus. However, these CES play a relatively minor role, controlling 2,297 MW of capacity out of a total of 77,191 MW, or less than 3 per cent.

Figure 4 shows the structure of the Korean electricity market.

Figure 4 Structure of the Korean power market



Source: KPX

Since 2008, the pricing system provides different generators different prices depending on their place in the merit order. The Cost Assessment Committee of the Korean Power Exchange, meeting monthly, estimates the marginal cost associated with each generation type. The highest marginal cost plant required in each hour defines the system marginal price (SMP). The price a generator ultimately receives is the sum of his variable cost and a percentage of the difference between the SMP and his variable cost: P = MC + k (SMP-MC), where k is the so-called SMP adjustment coefficient and is set between 0 and 1[2]. The lowest a generator can thus receive is the estimated marginal cost; the highest price is the SMP. However, the SMP adjustment coefficient is always set lower than one, except for pumped storage and renewable energy, so that only the very marginal (fossil) plant (where MC=SMP) actually receives the SMP. Most infra-marginal plants receive a downward-adjusted settlement price.

On top of the payments made for actual power production, all plants that have declared their availability receive a capacity payment.

For the purpose of establishing the marginal power plant we used price data from KPX (Korean Power Exchange). This data is given in Table 4 below. Due to the pricing system of the KPX, the marginal power plant always receives the highest price. Therefore the average settlement price is an indicator of where a technology stands in the merit order. This suggests that there are three sources which operate at the margin: LNG, oil and pumped storage power plants.

The emission intensity data for oil and LNG plants, also given in table 4 below, were calculated using the CARMA database (http://carma.org) and KEPCO's, and other generating companies' annual reports. The CARMA database gives emissions and electricity output for each power plant in Korea. We combined this information with information on fuel or technology taken from companies' annual reports. Table 4 below presents the resulting average emission intensity for oil and LNG plants.

Pumped storage uses off-peak (and hence low cost) electricity to pump water into a reservoir, from which it is released during peak demand. It does not 'generate' electricity in the classical sense. Given that it primarily acts as a storage technology, we attribute it with the average emissions intensity.

[2] P = MC + k (SMP-MC), 0<k<1 where k is the so-called SMP adjustment coefficient

Table 4 – Emission intensities of marginal technologies in Korea

Technology	Settled price (KRW/kWh)	Emission intensity – 2007 (gCO_2/kWh)
LNG	129.51	390.9
Oil	147.24	652.5
Pumped storage	149.70	455.8*

* This is the average emissions intensity of the South Korean grid

Source: KPX, CAIT, CARMA, KEPCO, EWP and Vivid Economics calculations

The Productivity Commission may also wish to take account of transmission and distribution losses. The World Bank World Development Indicators database reports that, as a proportion of output, transmission and distribution losses in Korea were 3.5%, 3.6% and 3.6% from 2005 to 2007 respectively.

6 United Kingdom

In a liberalised power market the marginal electricity source can be determined using either a merit-order based approach, or an empirical approach. The merit-order approach, defined as the order of dispatch according to cost of operation, yields a good approximation.

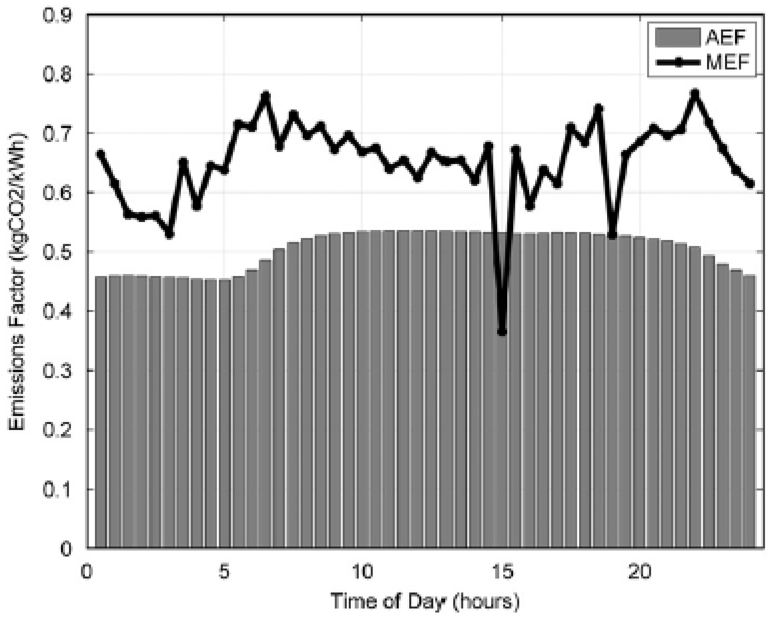
However, the merit-order approach relies on the assumption that the cheapest generators are dispatched first. While this is a reasonable approximation, as Hawkes (2010) notes: *cursory consideration suggests that the logistics of plant operation, transmission constraints, plant availability, and the vertically integrated nature of many utilities could all provide incentives or constraints that encourage operation in contravention of what is suggested by merit order.*

To overcome this problem, Hawkes (2010) undertakes a regression analysis between the change in system load and change in emissions for each settlement period between 2002 and 2009. He concludes that the average marginal emission intensity[3] of UK power generation is 690gCO_2/kWh.

This analysis also allows the author to assess the marginal emissions factor at different times of the day: the factor is found to be lower late at night and early in the morning as shown below.

[3] I.e. the slope of the regression between change in system load and change in carbon emissions

Figure 5 The marginal emissions factor tends to vary between 500 and 700gCO₂/kWh over the course of the day



Source: Hawkes (2010)

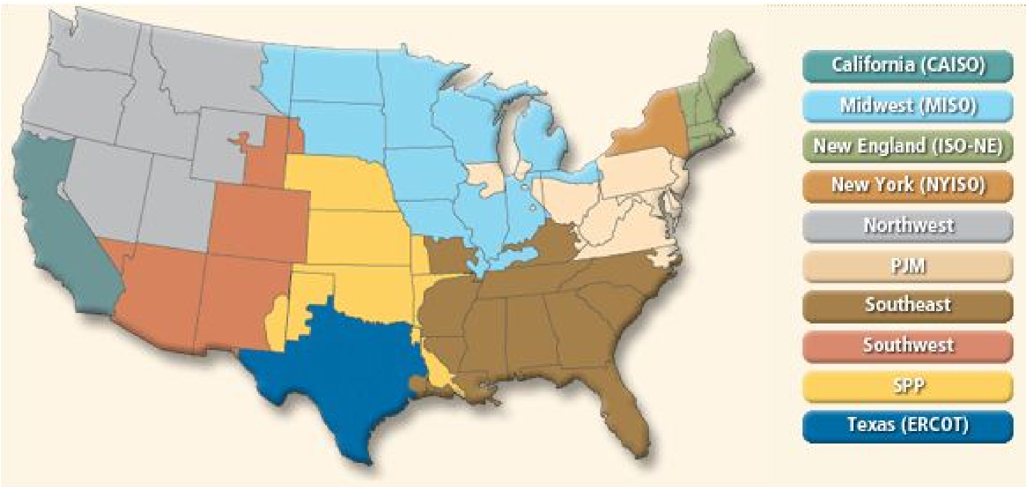
It should be noted that this represents the CO_2 emissions at the point of supply. The Productivity Commission may also wish to allow for transmission and distribution losses which are estimated to be 5.5% as a best estimate (DECC, 2009).

In relation to 'build margins' i.e. emissions of the marginal plant that is built or retired in response to policies that result in long-term changes to electricity demand or supply, to 2025, DECC expect this to continue to be a CCGT plant, and consequently advise that policy evaluation should be used assuming an emissions rate of 0.3939kgCO_2/kWh (DECC 2010). This is per unit of electricity consumed i.e. it takes account of transmission and distribution losses.

7 United States

Wholesale trading takes place in 10 different wholesale markets across the US as shown in Figure 6 below:

Figure 6 United States electricity markets



Source: FERC

Two models of wholesale regulation exist. Seven out of ten markets[4] are competitive spot markets operated by Independent System Operators (ISOs) or Regional Transmission Organisations (RTOs). The ISOs/RTOs operate and monitor power wholesale markets in their respective region and regulate access to and tariffs for transmission (subject to FERC approval). They do not own generation or transmission assets and are not owned or controlled by generation companies or transmission-owning utilities. They are quasi-public bodies, and publish annual State of the Market reports. Trading at these wholesale markets is via supply and demand bids. The least-cost supply offers are selected until demand is met, leading to a single market-clearing spot price.

The remaining three wholesale markets are run as a collection of bilateral exchange hubs. Sales and delivery take place at regional hubs, and prices are negotiated bilaterally, either directly, via brokers or on privately owned markets. Transmission is privately or publicly (through a publicly-owned utility) owned, but in either case subject to Open Access Transmission Tariff

[4] California, Midwest, New England, New York, PJM, SPP, Texas

(OATT) regulation issued by FERC. Transparency is generally less prevalent in these markets, as no central body is obliged to publish State of the Market reports.

Summary details of all ten US wholesale markets, including the marginal source of electricity for each, are given in table 5 below. The marginal electricity source or mix, and its corresponding emission intensity, is also given where available. The marginal sources of generation, and the relative proportion of time are taken from market monitoring reports published by the respective ISO/RTO market operators; based on these proportions, we have estimated a marginal emissions factor using plant-level emission data from CARMA, and plant-level fuel information from the EIA[5].

A brief summary of each of the markets is given beneath the table, including a detailed breakdown of the respective marginal source mixes.

[5]A total of 2925 plants have been processed for these calculations

Table 5 – United States electricity markets and marginal sources

Market	Spot-price trading?	Marginal Source	Estimate of Marginal Emission Factor, gCO_2/kWh
California (CAISO)	Yes	Gas	434.5 (2009)
Midwest (MISO)	Yes	Coal (73%), Gas (27%)	907.5 (2008)
New England (ISO-NE)	Yes	Gas (60%), Coal (14%)	600.3 (2009)
New York (NYISO)	Yes	Gas	597.3 (2009)
Northwest	No – bilateral	Hydro and Gas	N/A
PJM*	Yes	Coal (80%), Gas (20%)	792.4 (2010)
Southeast	No – bilateral	Coal and Gas	N/A
Southwest	No - bilateral	Gas	467.5 (2011)
SPP**	Yes	Coal (62%), Gas (38%)	794.8 (2010)
Texas (ERCOT)	Yes	Gas (73%), Coal (22%)	600.0 (2009)

* Pennsylvania – New Jersey – Maryland

** Southwest Power Pool

Sources: Federal Energy Regulatory Commission, PJM 2009 annual report, ERCOT 2009 State of the market report, SPP website, ISO/RTO council, CAISO 2008 annual report

The Productivity Commission may also wish to take account of transmission and distribution losses. The World Bank World Development Indicators database reports that, as a proportion of output, transmission and distribution losses in the US were 6.3%, 6.2% and 6.2% from 2005 to 2007 respectively.

7.1 Competitive spot markets

7.1.1 CAISO – California ISO

CAISO operates only in California, but is fully FERC-jurisdictional as the state's transmission grid is connected with the Western Interconnection. As of 2008, the total installed summer capacity in the CAISO region was 55,098 MW, making it the fifth-largest US wholesale market by capacity. Some public power systems in the state have chosen not to turn over operational control of their transmission facilities to CAISO. However, all public power systems are impacted by CAISO's spot market prices, which determine to a large extent which generators are brought on- and offline. Equally the provision of transmission service is strongly affected by CAISO's operations, as overall capacity is limited and as CAISO controls significant amounts of the transmission grid.

CAISO reports in its ZZ10-4 submission to the FERC that gas is usually the marginal fuel; using data from CARMA leads to an estimate of the emission intensity of gas-powered electricity of 462.5 gCO_2/kWh. Calculations from the Market Price Referent, used by the California Public Utilities commissions, imply an intensity of 406.1gCO_2/kWh. The marginal emissions factor is therefore likely to fall within this range.

Table 6 – Emission intensity by technology for CAISO

Technology	Proportion of marginal mix	Emission intensity (gCO_2/kWh)
Gas (CARMA data)	100%	462.5
Gas (MPR data)	100%	406.1

Sources: CAISO ZZ09-4 FERC filing, CARMA, EIA, and Vivid Economics

7.1.2 MISO – Midwest ISO

MISO operates in all or parts of Illinois, Indiana, Iowa, Kansas, Kentucky, Michigan, Minnesota, Missouri, Montana, Nebraska, North Dakota, Pennsylvania, South Dakota, Virginia, Wisconsin and Manitoba, Canada. As of 2008, there was 127,204 MW installed in the MISO region (summer capacity), making it the third-largest US wholesale market by capacity.

MISO reports in its ZZ09-4 submission to the FERC that the marginal plant is coal 73% of the time and gas 27% of the time. Using data from CARMA leads to a weighted average estimate of the marginal emission factor of 907.5gCO_2/kWh.

Table 7 – Emission intensity by technology for MISO

Technology	Proportion of marginal mix	Emission intensity (gCO_2/kWh)
Coal	73%	938.2
Gas	27%	824.7
Marginal Emissions Factor	N/A	907.5

Sources: MISO ZZ09-4 FERC filing, CARMA, EIA, and Vivid Economics

7.1.3 ISO-NE – New England ISO

ISO-NE operates in Maine, New Hampshire, Vermont, Massachusetts, Rhode Island, and Connecticut. As of 2008, total installed summer capacity was 31,088 MW. ISO-NE proposed to add a new locational generation capacity market (called Locational Installed Capacity or LICAP), which engendered great controversy in the region. However, most parties have now agreed to a settlement which replaces the LICAP proposal with a Forward Capacity Market (FCM). The Commission has approved the FCM settlement, but some parties, including the state of Maine, continue to oppose it.

ISO-NE reports in its 2009 State of the Market report that marginal plant in ISO-NE is gas 67% of the time, coal 18% of the time and hydro pumped storage 15% of the time. Using data from CARMA leads to a weighted average estimate of the marginal emission factor of 600.3gCO_2/kWh.

Table 8 – Emission intensity by technology for ISO-NE

Technology	Proportion of marginal mix	Emission intensity (gCO_2/kWh)
Gas	67%	538.4
Coal	18%	873.8
Pumped storage*	15%	548.5
Marginal Emissions Factor	N/A	600.3

* Pumped storage is attributed with the average grid intensity

Sources: ISO-NE, CARMA, EIA, CAIT and Vivid Economics

7.1.4 NYISO – New York ISO

NYISO operates only in New York, but is fully FERC-jurisdictional as the state's transmission grid is interconnected with the rest of the region. As of 2008, there was 40,187 MW of (summer) capacity installed in the region.

NYISO reports in its 2009 State of the Market report that Gas is usually the marginal plant; using data from CARMA leads to an estimate of the marginal emission factor as 597.3gCO_2/kWh.

Table 9 – Emission intensity by technology for NYISO

Technology	Proportion of marginal mix	Emission intensity (gCO_2/kWh)
Gas	100%	597.3
Marginal Emissions Factor	N/A	597.3

Sources: NYISO, CARMA, EIA, and Vivid Economics

7.1.5 PJM – Pennsylvania – New Jersey – Maryland RTO

PJM operates in all or parts of Delaware, Illinois, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. As of 2009, a total installed capacity of 164,895 MW (summer capacity) was located in the region, making it the second-largest US wholesale market by capacity. PJM faces substantial transmission constraints between its eastern and western regions. American Electric Power and Allegheny Power have both proposed to build substantial high voltage transmission projects from Western to Eastern PJM.

PJM reports in Volume 2 of its 2010 State of the Market report that the marginal source of power is coal 80% of the time and gas 20% of the time. This leads to an estimate of 792.4gCO_2/kWh.

Table 10 – Emission intensity by technology for PJM

Technology	Proportion of marginal mix	Emission intensity (gCO_2/kWh)
Coal	80%	845.0
Gas	20%	581.8
Marginal Emissions Factor	N/A	792.4

Sources: PJM, CARMA, EIA, and Vivid Economics

7.1.6 SPP – Southwest Power Pool

The SPP operates in all or parts of Arkansas, Kansas, Louisiana, Mississippi, Missouri, New Mexico, Oklahoma and Texas. As of 2008, 50,600 MW was connected to the SPP-controlled grid, making it the sixth-largest US wholesale market by capacity. The SPP introduced a real-time 'energy imbalance market' in February 2007 although the vast majority of the energy in SPP is supplied through bilateral contracts.

SPP reports in its December 2010 State of the Market report that coal is the marginal source 62% of the time and gas 38% of the time, leading to an estimate of the weighted average marginal emission factor of 794.8gCO_2/kWh.

Table 11 – Emission intensity by technology for SPP

Technology	Proportion of marginal mix	Emission intensity (gCO_2/kWh)
Coal	62%	954.0
Gas	38%	534.9
Marginal Emissions Factor	N/A	794.8

Sources: SPP, CARMA, EIA, and Vivid Economics

7.1.7 ERCOT – Electric Reliability Council of Texas

ERCOT covers the Texas Interconnection only. As of 2008, total installed summer capacity was 80,141 MW, making it the fourth-largest US wholesale market by capacity.

ERCOT reports in its 2009 State of the Market Report that gas is the marginal plant for 73% of the time, coal 22% of the time and wind 5% of the time. Using data from CARMA, we estimate the weighted average marginal emission factor to be 600.0gCO_2/kWh.

Table 12 – Emission intensity by technology for ERCOT

Technology	Proportion of marginal mix	Emission intensity (gCO_2/kWh)
Gas	73%	532.0
Coal	22%	962.2
Wind	5%	0
Marginal Emissions Factor	N/A	600.0

Sources: ERCOT, CARMA, EIA, and Vivid Economics

7.2 Bilateral Markets

7.2.1 Northwest

The Northwest market covers all or most of Washington State, Oregon, Idaho, Utah, Nevada, Montana, Wyoming, and a part of California. The two main trading hubs are California-Oregon Border, and Mid-Columbia. As of 2005, a generating capacity of 57,120 MW was connected to the grid in this area. The FERC reports that the two marginal sources in the Northwest are hydro and gas but does not report the relative frequency with which each source constitutes the marginal source.

Table 13 – Emission intensity by technology in the Northwest

Technology	Proportion of marginal mix	Emission intensity (gCO_2/kWh)
Gas	N/A	472.7
Hydro	N/A	0
Marginal Emissions Factor	N/A	N/A

Sources: FERC, CARMA, EIA, and Vivid Economics

7.2.2 Southwest

The Southwest market covers all or most of Arizona, New Mexico and Colorado, and parts of Nevada, Wyoming and South Dakota. There are three main trading hubs: Four Corners in New Mexico, Palo Verde in Arizona, and Mead in Nevada. As of 2005, a generating capacity of 45,459 MW was connected to the grid in this area, making it the third-smallest wholesale market in the US.

FERC reports that the marginal source in this market is gas. Using CARMA, we estimate that the marginal emission factor is 467.5gCO_2/kWh

Table 14 – Emission intensity by technology in the Southeast

Technology	Proportion of marginal mix	Emission intensity (gCO_2/kWh)
Gas	100%	467.5
Marginal Emissions Factor	N/A	467.5

Sources: FERC, CARMA, EIA, and Vivid Economics

7.2.3 Southeast

The Southeast market covers all or most of Florida, Arkansas, Louisiana, Mississippi, Alabama, Georgia, Tennessee, North Carolina, South Carolina, and parts of Missouri, Kentucky and Texas. It is the largest market by wholesale capacity, with an installed capacity of 299,712 as of 2006. Three very large integrated utilities operate in this market: Entergy, TVA, and Southern Company, covering between them all states in the Southeast market, except Florida, Virginia, and the Carolinas. The remaining four states are served largely by Duke Energy, Progress Energy, and other smaller integrated utilities.

The FERC reports that the marginal source in this market is coal and gas, but does not give a detailed breakdown by frequency.

Table 15 – Emission intensity by technology in the Southeast

Technology	Proportion of marginal mix	Emission intensity (gCO_2/kWh)
Gas	N/A	651.6
Coal	N/A	887.7
Marginal Emissions Factor	N/A	N/A

Sources: FERC, CARMA, EIA, and Vivid Economics

Sources

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