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Optimal Investment in Electricity Generation in the Texas Market

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ABSTRACT

This paper estimates an indicator of the investment that would occur under competitive procurement in Texas, and the associated efficiency gains. The paper presents a method to estimate the optimal investment in each technology available to generate electricity. The method determines the optimal investment by applying a similar logic that Borenstein (2005) uses to find the optimal long run capacity, but takes into consideration the current capacity. The estimation considers the expected entry and exit of generation plants and variations in future fuel prices. I conclude that for demand elasticities between -0.025 and -0.5, the investment in baseload (or coal) units that would generate a positive social surplus for all years from 2006 to 2011, ranges from about 12 to 37 thousand megawatts hour. Independent of the realized investment in baseload units, it is not optimal to invest in new peak or mid-merit units from 2006 to 2011. In a given year, the associated efficiency gains lie between, approximately, 865 and 7,617 million dollars depending on the year and assumption of demand elasticity. The equivalent per consumer figure ranges from, approximately, \$43 to \$380 per year. Introduction of carbon emission costs reduces substantially the investment in coal units that maximizes the social surplus. Considering a carbon allowance price is equal to two times that of the level in Europe, the optimal investment in coal units drops to zero. Introduction of carbon emission costs does not transform combined cycle or combustion turbine technologies into attractive technologies for investment.

Key words:
Optimal investment, Optimal capacity, Electricity generation, ERCOT

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1. INTRODUCTION

In the last two decades, a deregulation process has been initiated in many electricity markets around the world. One economic and political motivation for deregulation is that a system of competitive procurement of electricity provides better incentives for investment than the incentives created by either rate-of-return regulation or state-owned enterprises.

Much of the existing literature on deregulated electricity markets has focused on the short-run inefficiencies created by imperfectly competitive electricity spot markets[1]. Less research has focused on the longer-run incentives for optimal investment under competitive procurement[2]. This study addresses long run implications of deregulation – optimal investment in electricity generation.

The optimal investment is the investment that maximizes the social welfare. In a perfectly competitive market, private and social incentives are perfectly aligned, and there should be no gap between optimal and actual investment profile. Since most electricity markets are not perfectly competitive markets, comparison between optimal and observed investment provides a measure of how far the current system is from its optimal or ideal path. Moreover, the efficiency gains associated to the optimal investment provides a measure in dollars of the possible gains associated with decisions that favour a more competitive electricity market.

There are different technologies available to generate electricity. Natural gas-fired units include traditional single-cycle as well as new combined cycle gas turbines. Other generating units are fueled by coal and uranium. Finally, various renewable sources of energy include hydroelectric, wind, solar and geothermal technologies. The existing technology mix was largely determined under a more regulated regime. This paper estimates the change in technology mix that would occur in the long run under competitive procurement in Texas.

This paper introduces a methodology to estimate the optimal investment in each technology type. The method determines the optimal investment by applying a similar logic that Borenstein (2005a) uses to find the optimal long run capacity, but takes in consideration the current capacity[3]. The estimation procedure allows the system's capacity to change constantly to accommodate entry and exit of units, depending on the unit's schedule. Also the fuel prices change according to the expected future prices.

After having introduced the suggested method, I estimate an indicator of the optimal investment in electricity generation in Texas, more precisely, the subarea of Texas which is covered by the Electric Reliability Council of Texas (ERCOT) system. ERCOT manages the electricity market that covers about 75% of the state's land area, and 85% of the state's demand (load). The ERCOT market is not a

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[1] For example, see Wolfram (1999), Borenstein, Bushnell and Wolak (2002), Puller (2007), Bushnell, Mansur and Saravia (2005), and Hortacsu and Puller (2006).

[2] One paper that has studied the effects of deregulation on the efficiency of operations is Markiewicz, Rose, and Wolfram (2004).

[3] Joskow and Tirole (2004) also show how to find the optimal long run capacity. In contrast to Borenstein, they make some continuity and differentiability assumptions about the functions involved in the maximization problem.

competitive market, at least on the demand side. Most of the consumers are in the flat rate service, meaning that they pay fixed, previously established prices in peak and off peak hours. Assuming that energy suppliers are price takers, charging the Real Time Price (RTP)[4] would implement the optimal investment. The results suggest significant efficiency gains.

Limitations of the paper include the assumption of zero starting up costs[5] and, no uncertainty about demand or costs.

Subsection 2.1 reviews Borenstein's method to find the optimal long run composition. Subsection 2.2 explains the method proposed in this paper. Section 3 presents general aspects of the data used in this paper and the estimated marginal cost and demand curves. Section 4 discusses some characteristics of the plants operating in the ERCOT market that encourages consideration of the current composition when estimating the optimal investment. Finally, Section 5 presents some estimation criteria and an indicator of the optimal investment in the ERCOT market.

2. METHOD TO FIND THE OPTIMAL INVESTMENT PROFILE

2.1 Borenstein's method: *N* demands and *K* technologies

Borenstein (2005a) suggests a method to find the optimal long run capacity of each technology type for any specific distribution of demand functions. Before revising the method, I define a few terms. I call a vector of installed capacity for each technology type the current composition. Equivalently, I call a vector of optimal capacity for each technology type the optimal composition.

Suppose the electricity system faces different demands at different hours in a year. Assume there are N demands where $p^1(q)$ is the highest demand; $p^2(q)$ is the second highest demand; and so on. During α_n hours in a year, the system faces demand $p^n(q)$.

Assume that the capacity of each unit is 1 megawatt (MW) and the cost function of a unit that adopts technology i can be represented by the equation

$$C_i(q_i) = MC_i q_i$$

where MC_i is the marginal cost of a unit that adopts technology i and q_i is the quantity produced by the unit.

The annual capital cost of building one unit of technology i is ACC_i.

Suppose there are K technologies available to generate electricity. Technology 1 is the technology associated to the highest marginal cost; technology 2 is the technology associated to the second highest marginal cost; and so on. The order is reversed for the capital costs, technology 1 has the lowest capital cost; technology 2 has the second lowest capital cost; and so on. This inverse relationship between

[4] The price that clears the market at any time.

[5] The cost of turning on a unit.

marginal cost and fixed capital costs is consistent with technologies for electricity generation (e.g. natural gas peaking units have a high marginal cost but low fixed cost, while baseload coal-fired units have low marginal costs and high fixed costs).

The goal is to find the number of generators of each technology that maximizes the total welfare. First, imagine that all the production is provided by units that adopt the technology type associated with the highest marginal cost, technology 1. Then, add peak units into the system, one by one, until the introduction of one more unit would make the social surplus of the extra unit negative.

Start checking if it is socially optimal to invest in the first type-1-unit. For ease of graphical illustration, suppose that *N*=4. Imagine a case like the one represented in Figure 1. During α_4 hours, the unit will generate no surplus. During α_1 hours, the unit generates a social benefit of $\int_0^1 p^1(q)dq - MC_1$. During α_2 hours, the unit will generate a social benefit of $\int_0^1 p^2(q)dq - MC_1$, and so on. In the general case, it is welfare-increasing to invest in one type-1-unit if

$$\sum_{n=1}^{N} \alpha_n Max\left\{\int_0^1 p^n(q)dq - MC_1;0\right\} \geq ACC_1.$$

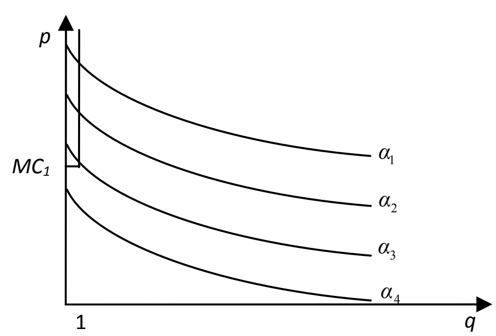


Figure 1

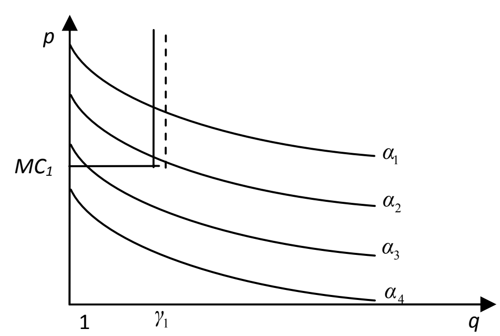


Figure 2

Now imagine that for the first γ_1 units, the social benefit and the annual capital cost were already compared, and it is optimal to invest in them. Now check if it is optimal to invest in one more unit, the $(\gamma_1 + 1)^{\text{th}}$ unit.

Calculate the social benefit for each demand and then add the social benefit for every demand multiplied by the number of hours in a year that the system faces this demand curve. For each demand curve, the social benefit generated by the extra unit is simply the area between the marginal cost curves, before and after the introduction of the extra type-1-unit, that lies below the demand curve.

Imagine a case like the one represented in Figure 2. During $(\alpha_4 + \alpha_3)$ hours, the extra unit generates no extra benefit. During α_1 hours, the extra unit will generate a social benefit of $\int_{\gamma_1}^{\gamma_1+1} p^1(q)dq - MC_1$. During α_2 hours, the benefit is $\int_{\gamma_1}^{\gamma_1+1} p^2(q)dq - MC_1$.

Generalizing, for any positive integer number *j*, it is welfare-increasing to invest in the $(j+1)^{\text{th}}$ type-1-unit if

$$\alpha_1 Max\left\{\int_j^{j+1} p^1(q)dq - MC_1;0\right\} + ... + \alpha_N Max\left\{\int_j^{j+1} p^N(q)dq - MC_1;0\right\} \geq ACC_1.$$

Equivalently,

$$\sum_{n=1}^{N} \alpha_n Max\left\{\int_j^{j+1} p^n(q)dq - MC_1;0\right\} \geq ACC_1.$$

Let C_{TO} be the number at which it is optimal to stop adding type-1-units to the system. When the number of type-1-units is equal to $(C_{TO}+1)$, the annual capital cost is higher than the benefit of an extra type-1-unit. Since each unit's capacity is 1 MW, C_{TO} is also the total capacity. Now consider the technology associated with the second highest marginal cost, technology 2. If replacing one type-1-unit for one type-2-unit increases the social welfare, it is optimal to replace it. Since $MC_1 > MC_2$, the type-2-unit will be operating before any type-1-unit.

Imagine a case like the one represented in Figure 3. The social benefit of replacing one type-1-unit for one type-2-unit is

$$(\alpha_1 + \alpha_2 + \alpha_3)(MC_1 - MC_2) + \alpha_4 \int_0^1 p^4(q)dq - MC_2.$$

The cost is $ACC_2 - ACC_1$. If the benefit is greater than the cost, then there is a social gain by replacing one more type-1-unit for one type-2-unit.

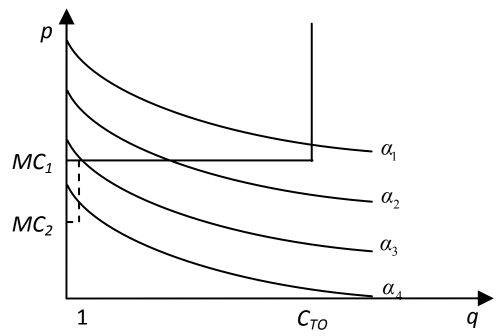


Figure 3

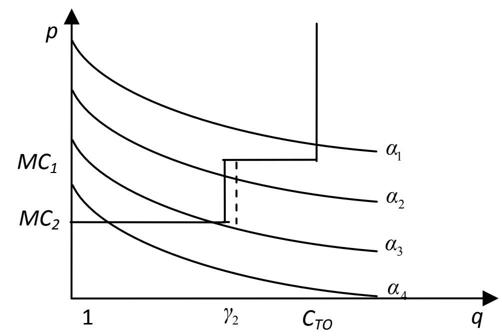


Figure 4

Now imagine that for the first γ_2 type-2-units, the social benefit and the annual capital cost were already compared, and it is optimal to replace γ_2 type-1-units with γ_2 type-2-units. Now check if it is optimal to replace, one more time, one type-1-unit for one type-2-unit, the $(\gamma_2 + 1)^{th}$ unit. Imagine a case like the one represented in Figure 4. During $(\alpha_4 + \alpha_3)$ hours, the replacement of one type-1-unit for one type-2-unit generates no extra surplus. During α_1 hours, the replacement generates a social benefit of $MC_2 - MC_1$. During α_2 hours, the social benefit is $\int_{\gamma_2}^{\gamma_2+1} p^2(q)dq - MC_2$. It is welfare-increasing to replace, one more time, one type-1-unit for one type-2-unit if

$$\alpha_1\left(MC_1 - MC_2\right) + \alpha_2\left(\int_{\gamma_2}^{\gamma_2+1} p^2(q)dq - MC_2\right) \geq ACC_2 - ACC_1.$$

Keep replacing type-1-units for type-2-units until the benefit is greater or equal to the additional fixed cost of type-2-units.

Repeat the procedure above for units of type 3, 4, and so on.

The trick is that replacing type-1-units for type-2-units does not change the optimal total capacity of the system. The reason is that, at any stage of the replacing process, the benefit and the cost of adding one extra type-1-unit to the system is always the same. At any stage the conclusion is the same: the benefit of adding one extra type-1-unit to the system does not pay its additional cost.

Borenstein assumes that the optimal composition contains strictly positive numbers of units for all technology types. In the case that the above procedure generates an optimal composition with null units for some technology, drop this technology from the set of possible technologies and start over again.

One might think that today's optimal investment in units that adopt a given technology type can be obtained simply subtracting its current capacity from its optimal capacity. This is true, only if, for each technology type, the current capacity is not greater than the optimal capacity. For purposes of today's optimal investment, the difference between optimal and current capacity is uninformative if for some technology, achieving the optimal capacity involves units shutting down. The following subsection will make this point clear.

2.2 Technological innovation and optimal investment in the short run: simple case

Consider a very simple environment in which the electricity system faces two kinds of demand, peak and off peak demands. Initially, there is only one technology to generate electricity, and a new technology is introduced. Call the old technology, technology 1, and the new technology, technology 2. Suppose that the new technology is better than the old one in the sense that it has a lower marginal cost and capital cost.

$$MC_1 > MC_2$$
$$ACC_1 > ACC_2$$

where the subscripts 1 and 2 refer to the old and new technologies.

Figure 5 represents the system's marginal cost curve before the technological advance. The long run optimal composition of technology types predicted by Borenstein implies replacement of all type-1-units for type-2-units. Imagine that the dashed line in Figure 6 represents the system's marginal cost curve associated to the long run optimal composition.

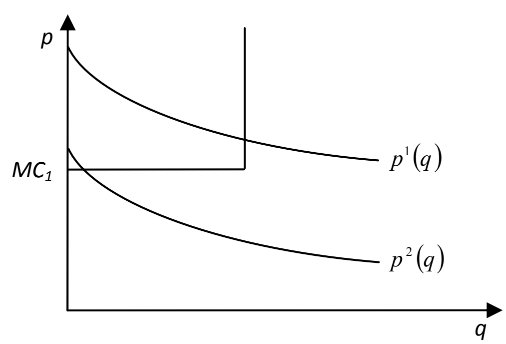


Figure 5

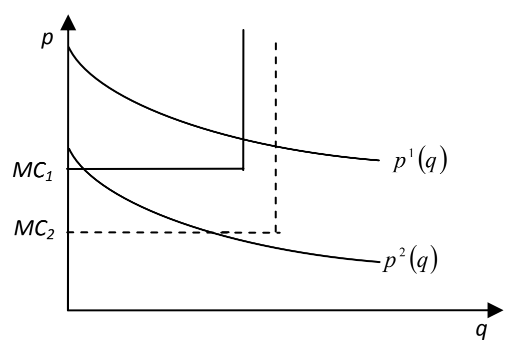


Figure 6

In this example, the comparison between the long run optimal composition and the current composition cannot help us to find today's optimal investment. The reason is that the calculation of the long run optimal composition does not consider that all units adopting the surpassed technology were already built. Their capital costs are already incurred at this stage; they are sunk costs.

If the goal is to find today's optimal investment, the relevant question is: Given the current composition, what is the optimal number of type-2-units that should be added to the system? Figure 7 shows the system's marginal cost for the current composition (solid line) and the system's marginal cost after adding one type-2-unit (dashed line). Adding one type-2-unit to the system will shift the system's marginal cost curve to the right and attach a segment of lower marginal cost to the first unit. Technology 2 is a baseload unit and will be operating before any type-1-unit.

During off peak hours, the social benefit of adding one type-2-unit to the system is equal to $MC_1 - MC_2$. During peak hours, the social benefit is equal to $MC_1 - MC_2$ plus the shaded area in Figure 7. The cost of adding one type-2-unit to the system is equal to the capital cost of type-2-units. If the benefit is greater than the cost it is optimal to add one type-2-unit to the system.

Now repeat the same procedure for the second type-2-unit, the third type-2-unit, and so on. The optimal solution will depend on the specific parameters of this problem. Figure 8 represents one possible solution for this case.

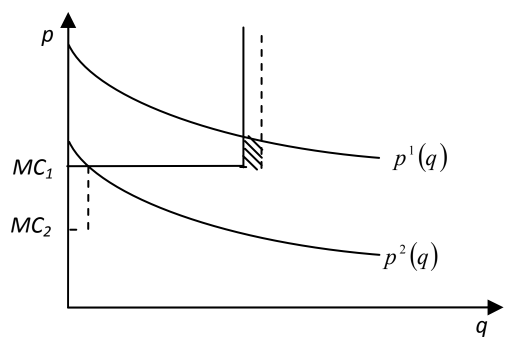


Figure 7

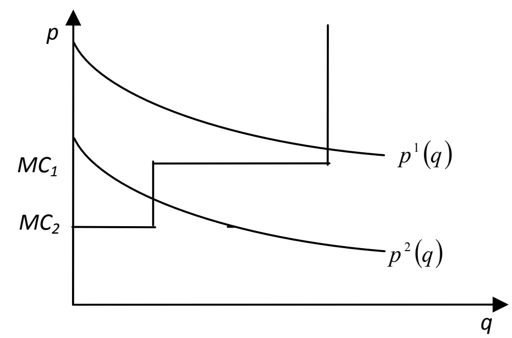


Figure 8

Note that, differently from the long run optimal capacity, the optimal investment in the short run does not involve complete replacement of the old units.

The reason for the optimal investment in the short run not being equal to the difference between the long run optimal composition and the current composition is that the optimal long run composition involves closing some units currently operating.

Not only technological innovations can lead to a violation of the condition that for all technologies the optimal capacity is greater than its current capacity. For instance, an unexpected increase in the price of a fuel may reduce the optimal capacity of a given technology type to a level below the current capacity. Also, the electricity market in Texas is not a perfectly competitive market and The First Theorem of Social Welfare does not necessary hold. So, it is possible that either the regulatory authority (under the traditional regulatory regime) or profit maximizing agents (since restructuring began) over invested in some technologies in the past.

No matter what the current composition of generators is, the method introduced in this paper allows us to calculate today's optimal investment in each technology type. In the following section, I extend the method introduced in this subsection to N demands, K technologies currently being used and L technologies qualified to receive positive investment.

2.3 Optimal investment in the short run: *N* demands, *K* technologies currently being used and *L* technologies qualified to receive positive investment

Assume there are N demands. $p^1(q)$ is the highest demand, $p^2(q)$ is the second highest demand, and so on. During α_n hours in a year the system faces demand $p^n(q)$. There are K different technologies currently being used to generate electricity. Technology 1 is the technology associated to the highest marginal cost; technology 2 is the technology associated to the second highest marginal cost; and so on. It is possible that some of the technologies currently being used to generate electricity do not belong to the optimal long run composition.

Suppose there are L technologies qualified to receive positive investments. By qualified, I mean the technologies belonging in the optimal long run composition. The set of qualified technologies can contain all, none or some of the technologies currently being used. It can also contain some technologies that were not yet used (i.e. new technologies). Let $L1$ be the qualified technology associated to the highest marginal cost and lowest capital cost among the qualified technologies; $L2$ be the qualified technology associated with the second highest marginal cost and second lowest capital cost, and so on.

For simplicity, assume that no generation unit will close or is planned to be opened during the covered period.

For matters of graphical illustration, suppose that the full line in Figure 9 represents the system's marginal cost. Also, suppose that $N=6$.

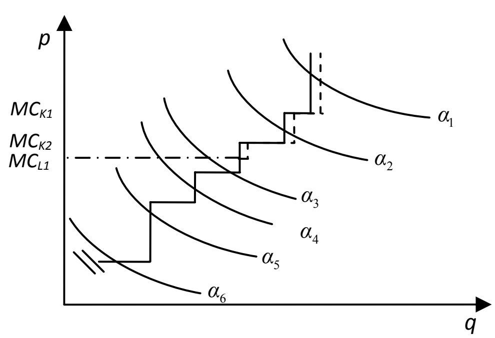


Figure 9

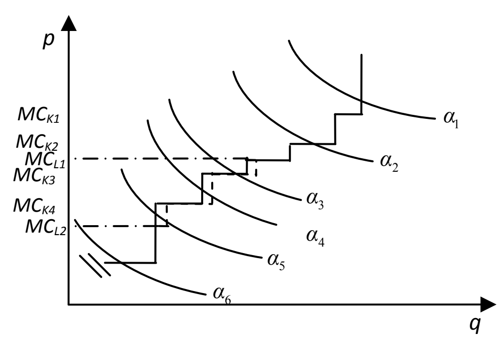


Figure 10

Consider the qualified technology with the highest marginal cost, $L1$. The goal is to check if adding one type-$L1$-unit to the system will generate a social surplus. For each demand function, calculate the social benefit and then just add the social benefit for every demand multiplied by the number of hours in a year that the system faces each demand curve. The social benefit generated by the extra unit is simply the area between the marginal cost curves before and after the introduction of the extra type-$L1$-unit, that lies below the demand curve.

Let MC_{L1} in Figure 9 represents the marginal cost of type-*L1*-units and MC_{Ki} represent the marginal cost of type-*Ki*-units. Adding one type-*L1*-unit, will shift the segment of the system's marginal cost curve above MC_{L1} to the right (dashed line in Figure 9).

During $(\alpha_6 + \alpha_5 + \alpha_4 + \alpha_3)$ hours in a year, there is no extra benefit in adding one type-*L1*-unit to the system. During α_2 hours, the benefit of adding one type-*L1*-unit is $\int_{\sum_{k=2}^{K}\psi_k}^{\sum_{k=2}^{K}\psi_k+1} p^2(q)dq - MC_{K2} + (MC_{K2} - MC_{L1})$, where ψ_k is the number of units of technology type *k* currently operating. During α_1 hours, the benefit of adding one type-*L1*-unit is

$$\int_{\sum_{k=1}^{K}\psi_k}^{\sum_{k=1}^{K}\psi_k+1} p^1(q)dq - MC_{K1} + (MC_{K1} - MC_{K2}) + (MC_{K2} - MC_{L1}).$$

It is socially optimal to invest in one type-*L1*-unit if the total benefit is greater or equal to the capital cost of type-*L1*-units.

Add type-*L1*-units to the system, one by one, until the benefit is equal or smaller to the cost. Call ψ_{TO}^{L} the number at which it is optimal to stop adding type-*L1*-units to the system.

When the number of type-*L1*-units is equal to ψ_{TO}^{L} the cost of one extra type-*L1*-unit is higher than its benefit. Since each unit produces 1 MW, ψ_{TO}^{L} is also the total capacity added to the system.

Now consider the qualified technology associated with the second highest marginal cost, technology *L2*. Check if replacing one type-*L1*-unit for one type-*L2*-unit increases the social welfare, if so; it is optimal to replace it. Since $MC_{L1} > MC_{L2}$ the type-*L2*-unit will be used before any type-*L1*-unit.

Consider the case illustrated in Figure 10. During α_6 hours in a year, there is no extra benefit in replace one type-*L1*-unit for one type-*L2*-unit. During α_5 hours the benefit of replacing one type-*L1*-unit for one type-*L2*-unit is $\int_{\sum_{k=5}^{K}\psi_k}^{\sum_{k=5}^{K}\psi_k+1} p^5(q)dq - MC_{L2}$.

During α_4 hours the social benefit is $\int_{\sum_{k=4}^{K}\psi_k}^{\sum_{k=4}^{K}\psi_k+1} p^4(q)dq - MC_{K4} + (MC_{K4} - MC_{L2})$.

During α_3 hours the social benefit is $(MC_{K3} - MC_{K4}) + (MC_{K4} - MC_{L2})$.

During $(\alpha_1 + \alpha_2)$ hours the social benefit is

$$(MC_{L1} - MC_{K3}) + (MC_{K3} - MC_{K4}) + (MC_{K4} - MC_{L2}).$$

The difference in cost is ACC_{L1}-ACC_{L2}. If the benefit is greater or equal to the cost there is a social gain in replace one type-*L1*-unit for one type-*L2*-unit.

Keep replacing type-*L1*-units for type-*L2*-units until the benefit is equal or lower than the extra capital cost of type-*L2*-units.

The trick is that the optimal total capacity *added* to the system does not change when type-*L1*-units are replaced by type-*L2*-units. At any stage of the replacing process, the benefit and cost of adding one more type-*L1*-unit to the system is always the same. At any stage, the conclusion is the same: the benefit of adding one extra type-*L1*-unit to the system does not pay its cost.

Repeat the procedure above for units of type *L3*, *L4*, and so on. The solution is a profile of investment that specifies the optimal investment today in all types of qualified technologies, $(\delta_1,...,\delta_L)$.

So far, it was assumed that no unit will close or is planned to be opened in the covered year. In general, this assumption will not hold. In this case, when calculating the social benefit that an extra unit will generate in a given hour of the year, one has to consider the capacity available at that same hour.

For simplicity, it was assumed that the marginal cost of any unit is constant over the year. The marginal cost depends on inputs prices, and those vary significantly over the year. The solution is straightforward, when calculating the social benefit that an extra unit will generate in a given hour of the year, one has to consider the marginal costs in that same hour.

The above procedure works fine if the optimal investment profile consists of strictly positive numbers of units for all *Li* technologies. If at some stage of the above procedure it is not optimal to invest in some technology *Li*, this technology should be dropped from the set of technologies qualified to receive positive investments, *L*, and the procedure should be restarted.

Note that, under perfect competition, social and private interests are perfect aligned. Profit maximizing agents have no incentive to invest differently from the optimal investment level. Nevertheless, electricity markets, usually, are not competitive markets.

3. DATA, MARGINAL COST AND DEMAND CURVES

3.1 Data description

Data from Platts, an energy information service, provide information on all electricity generator units opened or planned to be opened from 1990 until 2050 in the ERCOT system. They are 1067 units in total. For each unit, data are available on the date it started or will start operating in the ERCOT system; if the plant is now operating, out of service, retired or planned to be retired soon, its production capacities in MW, the primary turbine mover used to generate electricity, the primary fuel used by this unit, and the amount of the corresponding fuel necessary to generate one MW of electricity (heat rate). Table 1 presents the combinations of turbine mover and fuel observed in ERCOT, as well as, the percentage of each combination in the total production capacity in ERCOT and some basic statistics.

Table 1: Basic statistics for the electricity generation units operating in Texas in 2005

primary turbine mover	primary fuel	number of Plants	total capacity (in MWh)	percentages of total capacity
COMBINED CYCLE	Natural Gas	105	31,592.43	34.59
STEAM	Natural Gas	151	28,345.55	31.03
STEAM	Lignite (coal)	14	8,523.20	9.33
STEAM	Sub-bituminous (coal)	18	7,069.29	7.74
GAS TURBINE	Natural Gas	141	7,040.55	7.71
NUCLEAR	Uranium	8	5,138.60	5.63
WIND	Wind	35	1,700.30	1.86
STEAM	Bituminous (coal)	1	600.40	0.66
HYDRO	Water	44	423.84	0.46
OTHERS	NA	128	900.25	0.99
TOTAL		645	91,334.41	100.00

Source: Platts, 2005

The data for demand were obtained from the ERCOT website. For every day of 2005, the data provides the electricity demand for each 15 minutes interval starting from midnight. The load duration curve for 2005 is represented in Figure A1. For any quantity Q in the horizontal axis, the vertical axis shows the percentage of hours a year in which the demand is equal or greater than Q.

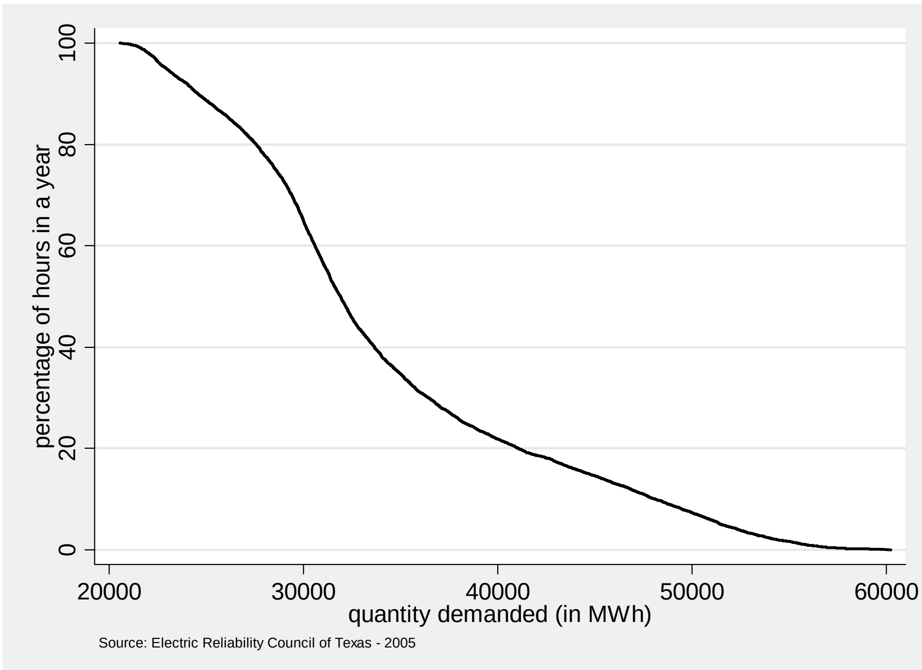
3.2 Marginal cost

The marginal cost of electricity consist of two components: the fuel cost and other variable operating or maintenance cost. The marginal cost of a unit *i* is given by the equation:

$$MC_i = \textit{maintenance cost} + \textit{heat rate}_i \times \textit{fuel price}$$

The maintenance costs are assumed to be two dollars per MW, which is an appropriate figure for the ERCOT system.

FIGURE A1: ERCOT load in 2005



The heat rates are unknown for about 30% of the units operating in 2005. A missing value is replaced by the average heat rate of units with the same turbine mover and fuel needs. The average is calculated considering the units opened two years before, two years after and in the year that the considered unit were opened.

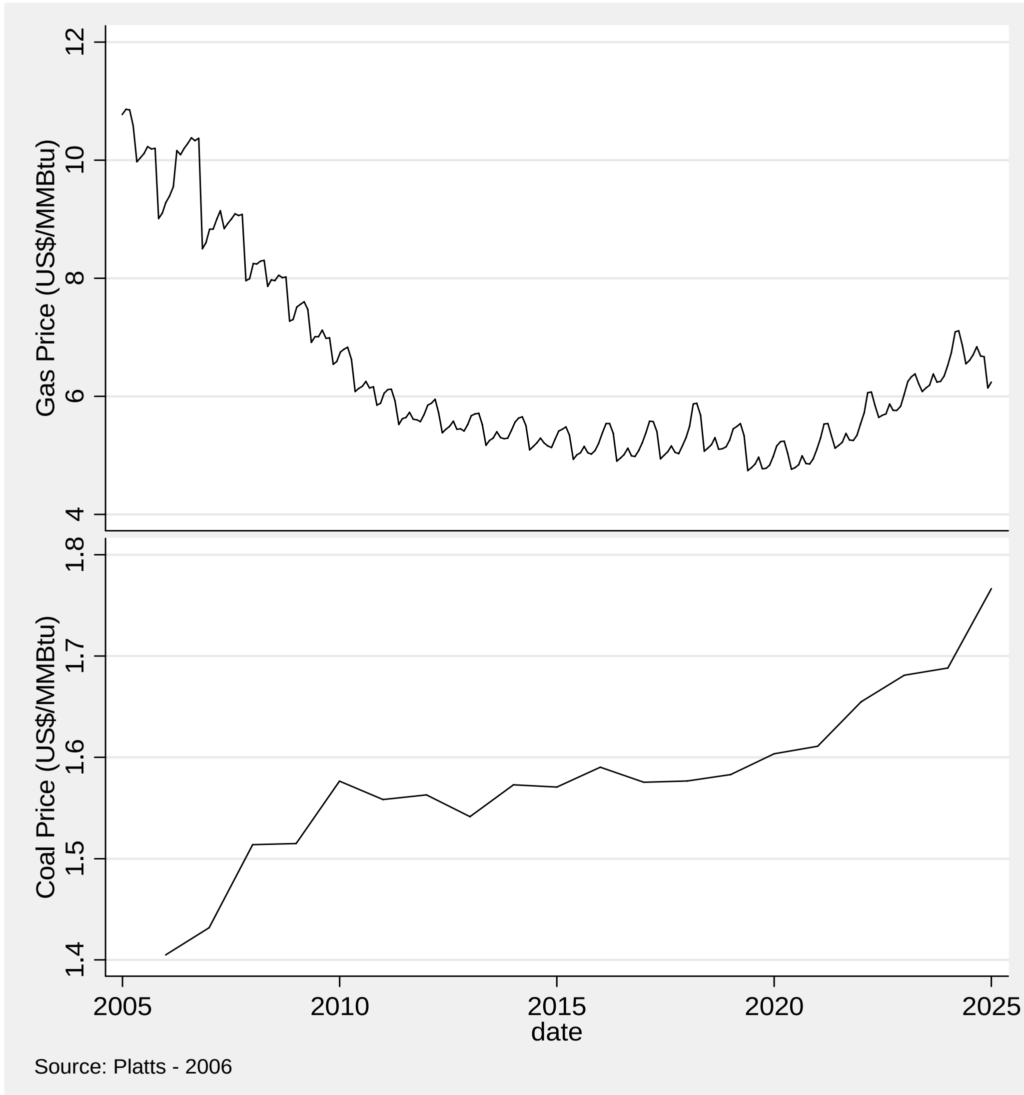
Another variable in the marginal cost equation is the fuel price. A high share of the electricity generated in the ERCOT system is supplied by plants that use as inputs coal, natural gas or uranium. According to Ux Consulting Company, the estimated price of uranium on March 20th was 40.50[6] dollars per lb.

The future prices for coal and gas was obtained at Platts website. It is available monthly gas price and yearly coal prices, both for Texas, until 2025. Figure A2 presents the evolution of gas and coal prices during the period.

The prices for all other fuels are not available. The fuel cost of all units with missing heat rate and/or missing fuel price is set to zero. This makes our final results a lower bound estimator of the optimal investment in each technology type. To deal differently with the missing values should not change our results significantly, since the combined production capacity of all units with missing heat rate and/or missing fuel price do not represent a significant share of the total capacity, 2,789.1 MW out of 94,571.51 MW.

[6] See http://www.uxc.com.

FIGURE A2: Gas and coal future prices



The estimated marginal cost curve in January of 2006 is represented in Figure A3[7]. Note that much more than 2,789.1 MW of generation capacity are associated with marginal cost of about two dollars. This happens for two reasons. First, the marginal cost of nuclear units is just slightly higher than two dollars. Second, the heat rate of units that use water, wind or sun as a primary mover is zero.

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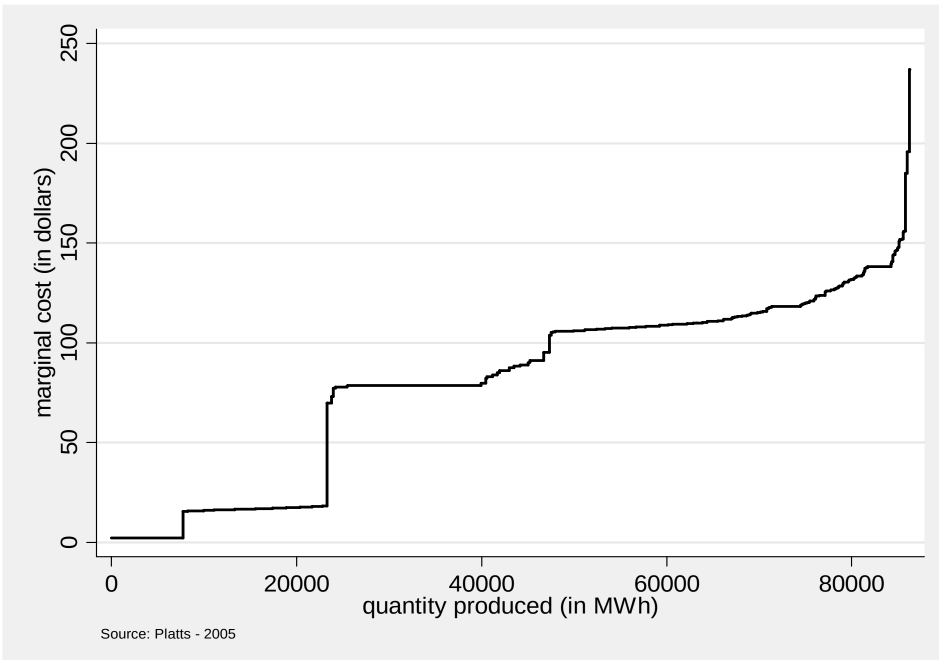
[7] In 2006, the difference between Summer and Winter capacities was 2,607 MW. Since this difference does not represent a significant percentage of total capacity, I do not consider variations between Summer and Winter capacities.

FIGURE A3: Estimated ERCOT System's marginal cost in January of 2006



3.3 Demand curves

Like in Borenstein (2005a), the assumed hourly demand specification is given by the equation:

$$D_h(p_h,\bar{p}) = aA_h p_h^{\varepsilon} + (1-a)A_h \bar{p}^{\varepsilon}$$

where a represents the share of the demand in real time price (RTP), p_h represents the RTP of electricity at hour h, $\bar{p}$ represents the price charged to consumers in flat rate service, and ε represents the elasticity of demand.

a is assumed to be equal to one percent[8]. The price charged to consumers on the flat rate service used in the estimations was 14 cents per kWh of electricity[9].

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[8] I did not find any data or study that estimate the percentage of consumers in the RTP. This number was suggested by an industry analyst.

[9] The price considered was given by an industry analyst. This number is also consistent with the the prices available at the site http://www.electricitytexas.com. For each zip code in Texas, this site informs the electricity prices charged by some electricity providers in the corresponding area. For instance, in September, 26th of 2006, the simple average of electricity prices was 13.98 cents per kWh in Dallas and Waco and, 14.98 in Houston. Depending on the area, provider and payment plan; Summer and Winter rates may differ. But the difference does not seem to be significant. For instance, the Summer and Winter rates differ in 0.14 cents per kWh in College Station.

Following Borenstein, the cost of transmission & distribution is set equal to 4 cents per kWh, and should be deducted from the flat rate and the RTP when estimating the hourly demand curves. Estimations of the demand elasticity are not available. Like in Borenstein, a wide range of possible values assumed by ε is considered. This way, the final result is a range for the optimal investment in each technology type.

Knowing the real time prices and the hourly quantity demanded, the only parameter left to be estimated in the demand equation is A_h. In fact, the data do not provide information on real time prices. The RTP is estimated assuming that the real time market is a perfectly competitive market[10]. For a given quantity demanded, the RTP is set equal to the marginal cost at that quantity. Whenever a quantity demanded is associated to a vertical segment in the marginal cost curve, the price is set equal to the medium point in the vertical segment.

Knowing a, $\overline{p}$, D_h, p_h, one can calculate A_h for different values of elasticity. Once A_h is calculated, it is possible to calculate the demand curves for any value of a between zero and one. For matters of calculating consumer surplus for the optimal investment algorithm, a can only assume the value one. This is because when calculating the social surplus, what matters is the price the consumers are willing to pay for each MW and not the price they actually pay. So, a is set equal to one when the optimal investment is calculated.

The marginal cost curve in January of 2006, the predicted real time prices (for a equal to 0.01), as well as, some estimated demand curves (for a equal to 1) are represented in Figure A4. The upper part of Figure A4 shows the estimated demand curves assuming the demand elasticity level of -0.025, and the bottom shows the demands for the elasticity level of -0.5. The highest and the lowest demand curves are represented in both cases.

Before proceeding with the estimations, the following section discuss some aspects of the plants operating in the ERCOT market that raise concerns about estimations of the optimal investment that do not take in consideration the current composition.

4. HIGH VERSUS LOW DEPRECIATION RATE

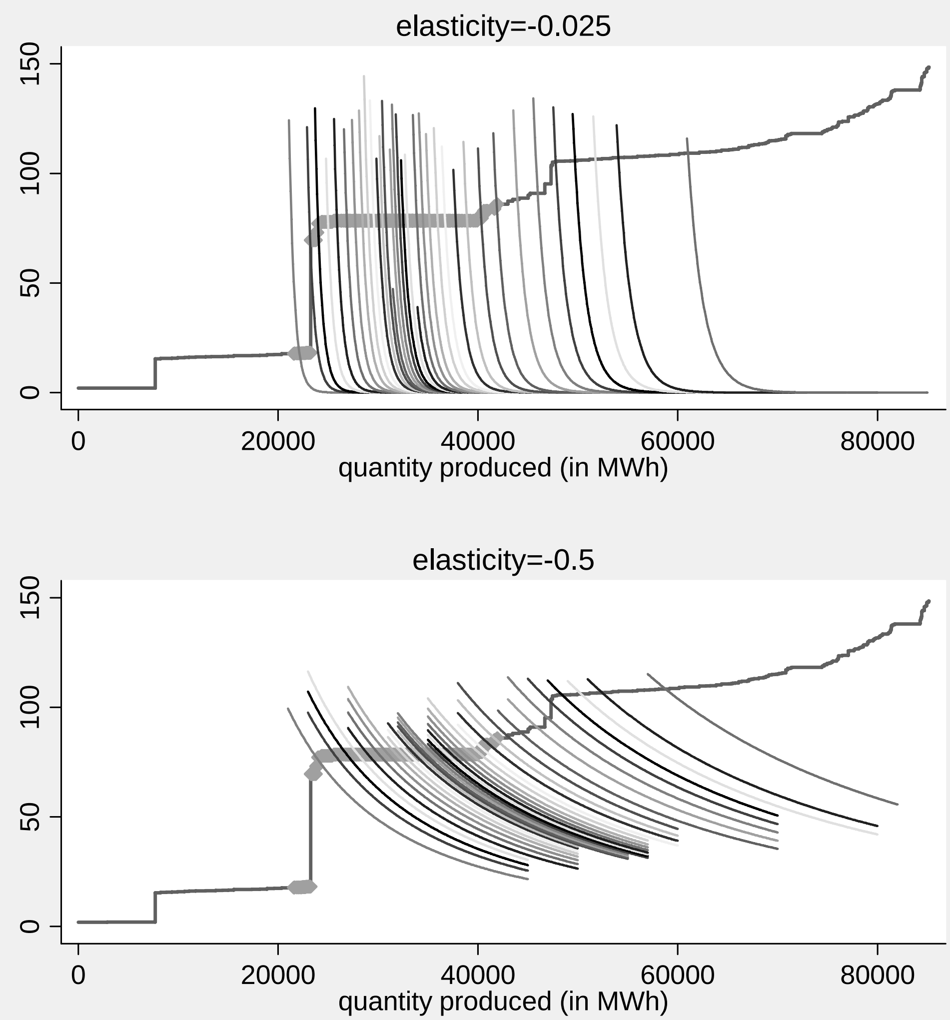
This paper's focus is in optimal investment while Borenstein's paper discusses optimal long run capacity. Assuming that the depreciation rate is higher than a certain threshold, today's optimal investment is simply the optimal long run composition. Finding evidence supporting the hypothesis of a high depreciation rate, would suggest a fast adjustment toward the long run optimal composition. In this case, considerations of the current capacity are unnecessary, and the optimal investment would be equal the optimal long run capacity.

Depending on the plan, this difference goes from zero to 1.5 cents per kWh for the Reliant Energy in Houston.

[10] Other price setting, like Cournot Model, can be considered. Nevertheless, the result should not change significantly. Since the share of consumers in the RTP is very small, variations in the RTP have little impact in the parameter A_h.

If all units in the ERCOT market last just a few years, it would suggest a pretty high depreciation rate. The upper part of Figure A5 shows the histogram of the age of units that already closed or have established a retirement date. The bottom part shows the same histogram weighted by capacity. Once a capacity is installed, in general, it will be operating for forty years. The histograms suggest a low depreciation rate.

FIGURE A4: System's marginal cost curve in January of 2006, and some estimated demand curves in 2006 for a=1. The upper part of the graph shows the estimated demand curves assuming the elasticity level of -0.025, and the bottom shows the demands for the elasticity level of -0.5. The estimated RTP for a=0.01 in January of 2006 are represented by the gray dots in the marginal cost curve.



Source : Platts and Electric Reliability Council of Texas - 2005

FIGURE A5: Histograms of the age of the units that already closed or have established a retirement date. The bottom part shows the histogram weighted by capacity.

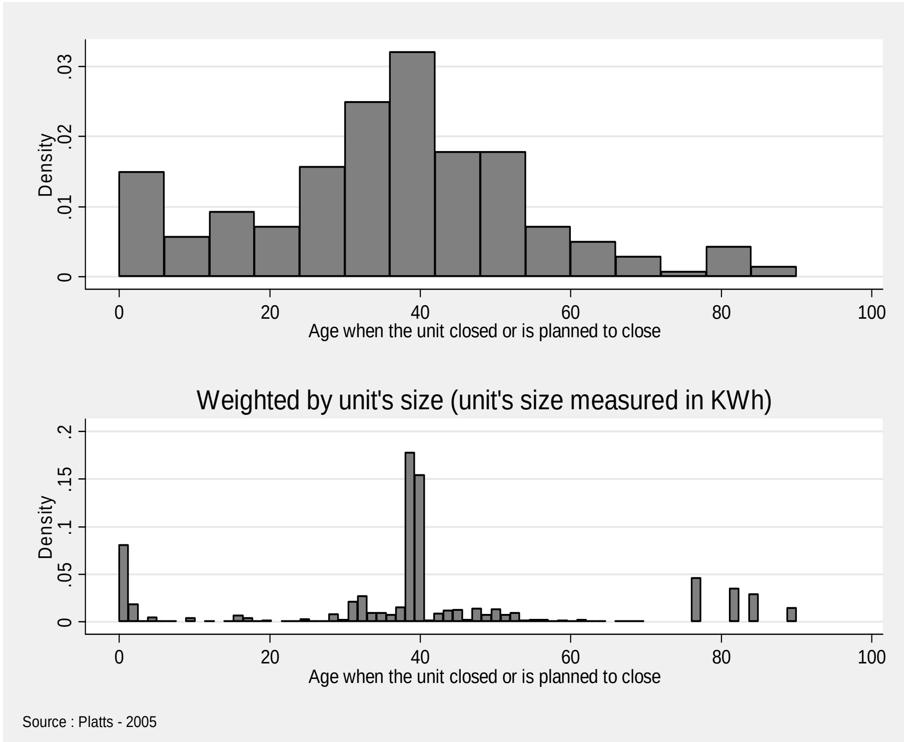
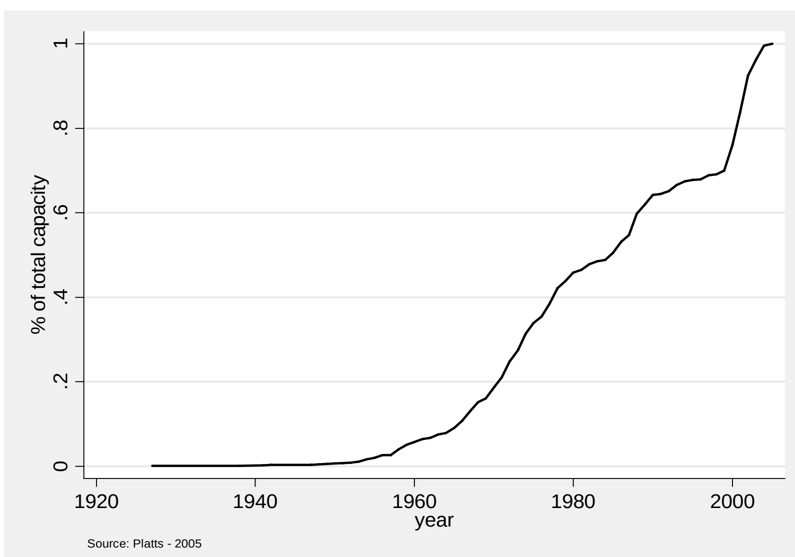


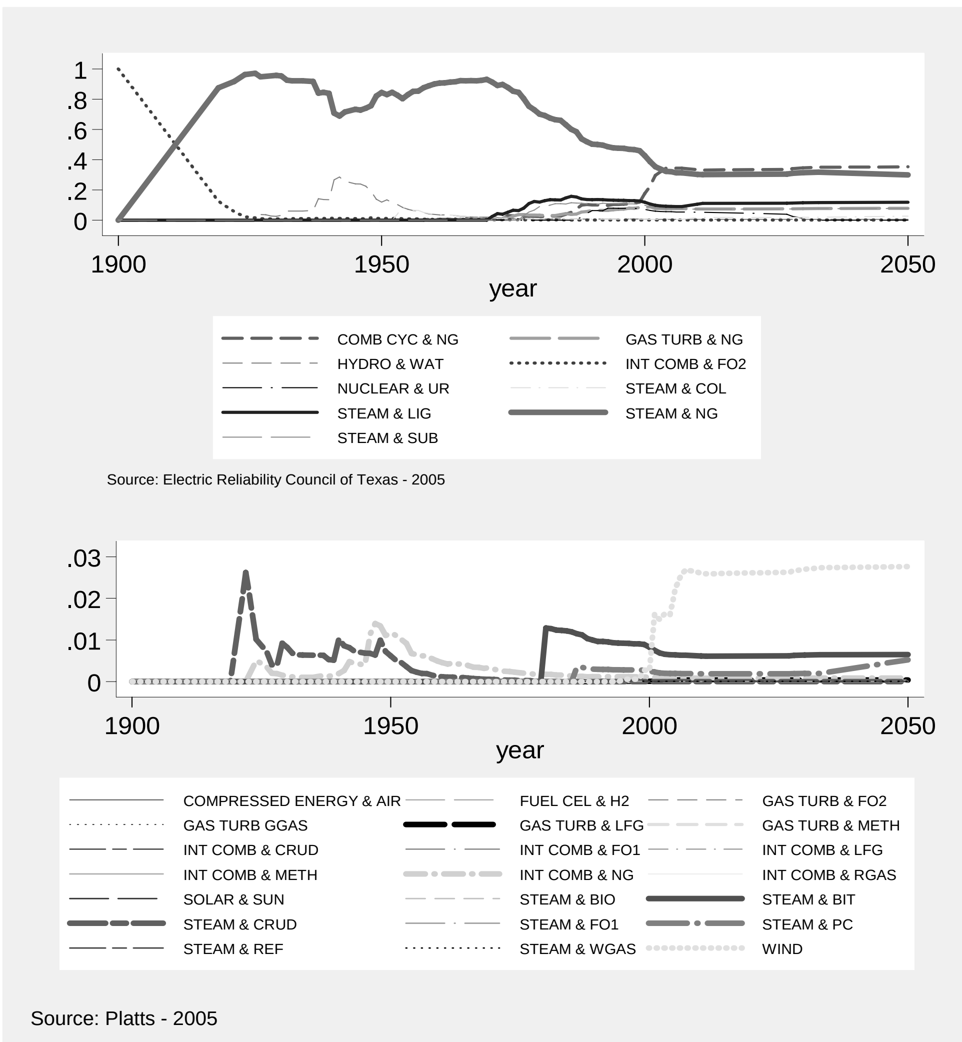
FIGURE A6: The vertical axis shows how much of 2005's total capacity is supplied by units built before or in the corresponding year in the horizontal axis. Only the units operating in October of 2005 were considered.



If the current composition consists of relatively new units, it can be an argument in favour of the hypothesis of a high depreciation rate. Figure A6 shows how much of the current total capacity is supplied by units built before or in the corresponding year in the horizontal axis. For instance, more than 40% of 2005's capacity was built in 1980 or before. The fact that a large fraction of the 2005's capacity is supplied by relatively old units supports the hypothesis of a low depreciation rate.

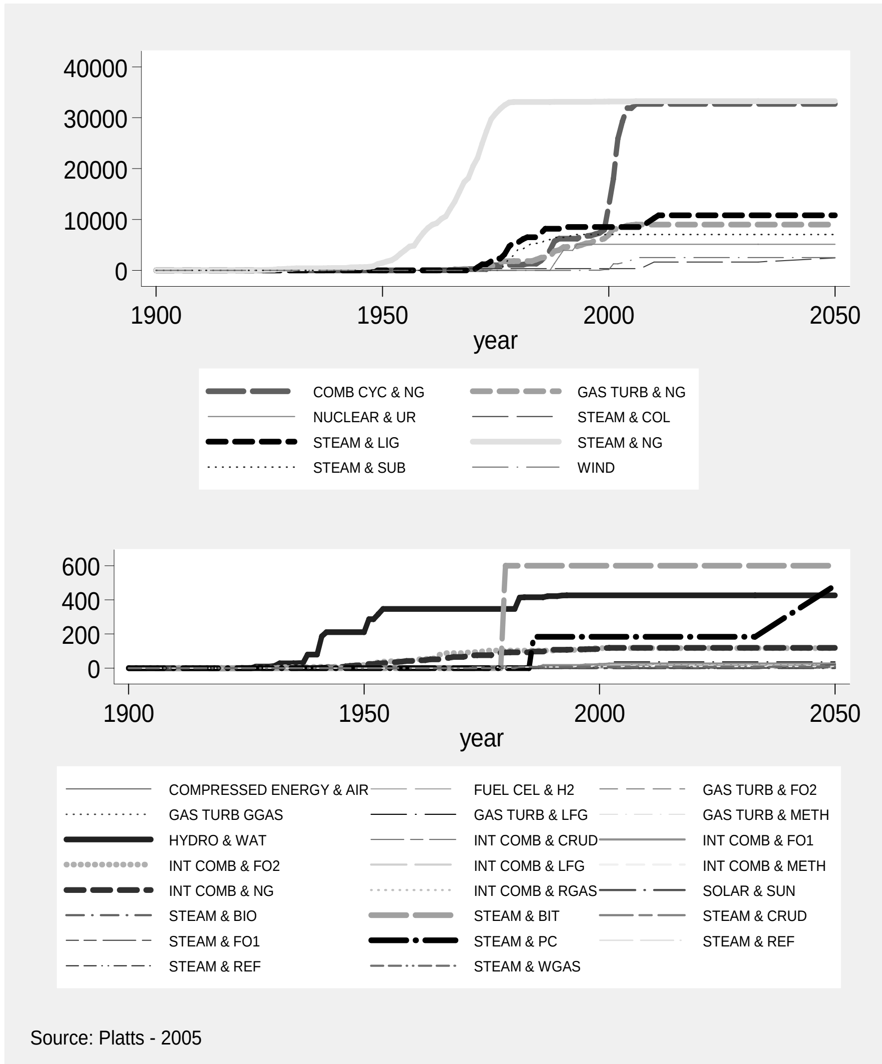
The supply composition experienced great changes during the period covered as shown in Figure A7.

FIGURE A7:
For each year, the graph shows the percentage of total capacity in that year that is supplied by a specific technology.



For each year in the horizontal axis, it shows the percentage of the total capacity that year that is produced by a specific combination of turbine and fuel type[11]. Most of the movements in the curves in Figure A7 were driven by the addition of new capacity. Retirement explains just a tiny part of the movement.

FIGURE A8: Capacity added (in MW) over year by technology.

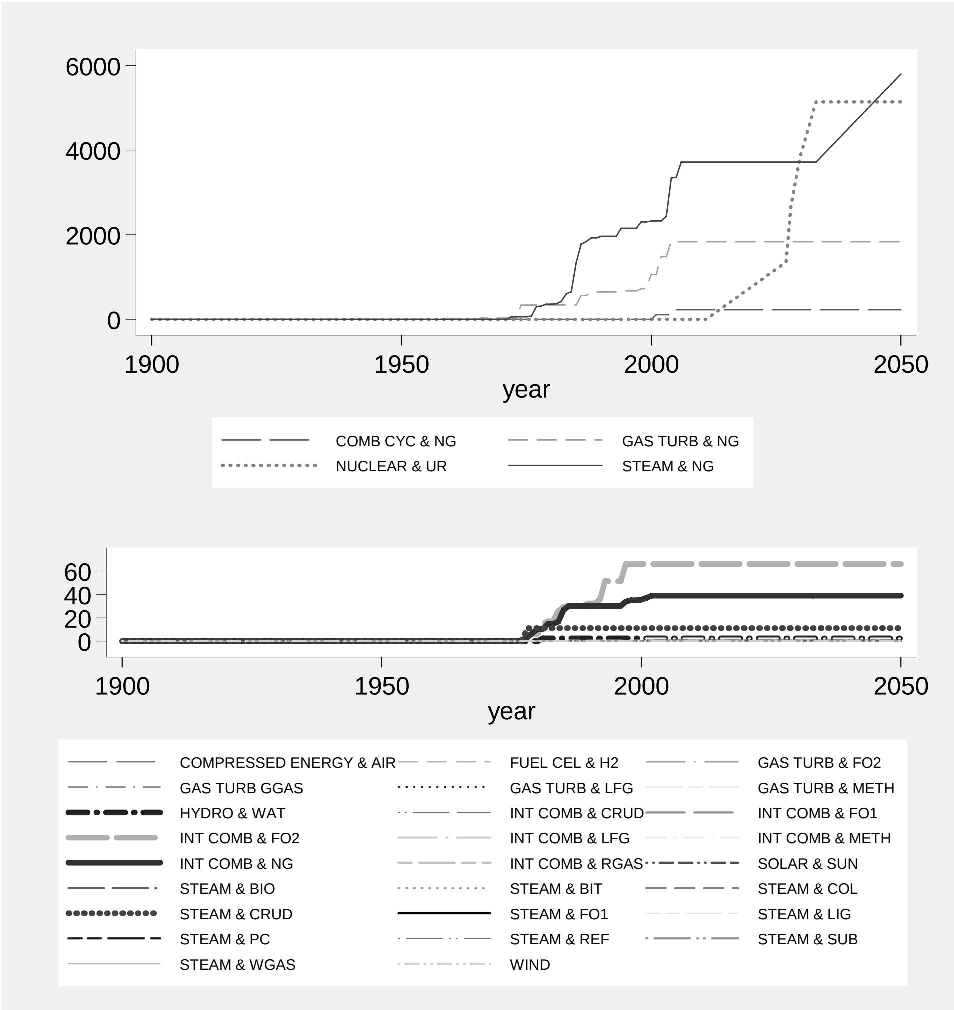


Source: Platts - 2005

[11] The figure is split in two parts because of the great differences in the y-axis scale across combinations over time. In a given year the capacities shown in the figure include the capacity of units operating, in stand by, retired, under construction, in early development and proposed if the unit is open or planned to be open in that year. The capacity of canceled units and planned units indefinitely postponed were excluded.

Description of the codes in the figure: BIT (Bituminous), COL (Coal), CRUD (Crude Oil), FO1 (Fuel Oil 1), FO2 (Fuel Oil 2), GGAS (Generic Gas), LFG (Landfill gas), LIG (Lignite), METH (Methane), NG (Natural Gas), PC (PetCoke), RGAS (Refinery Gas), REF (Refuse - trash), STM (Steam), SUB (Sub-Bituminous), UR (Uranium), WAT (Water) and, WGAS (Waste Gas).

FIGURE A9: Capacity retired (in MW) over year by technology



Source: Platts - 2005

Retirement explains just a tiny part of the movement. Figure A8 and A9 show, for each combination of turbine and fuel, the evolution of the capacity added and retired, respectively. Despite the major structural changes in the electricity supply over the years, the adjustment seems to happen via addition of new capacity and, seldom, via retirement of capacity.

This section presents some evidence supporting the hypothesis of a low depreciation rate[12]; consequently a slow adjustment process toward the optimal long

[12] Caution is recommended here, since it is possible that all units currently operating belong to the composition that minimizes production costs. Maybe some of the old units currently operating in the ERCOT market have been completely remodeled since their inauguration; and that is the reason why they remained in the market in the first place.

run composition. Therefore, considerations of the current capacity are recommended when estimating the optimal investment[13].

5. Estimation's procedure and results

Borenstein (2006a) applies the method presented in section 2.1 to calculated the optimal long run capacity while, this section, apply the method presented in section 2.3 to calculate the optimal investment.

Borenstein (2005a) consider three technologies in the set of optimal long run composition. They are: coal units, combined-cycle gas turbine, and combustion turbine generation, representing baseload, mid-merit, and peak technologies, respectively. Here the three technologies are considered as technologies qualified to receive positive investments. The annual capital costs adopted are the ones provided by Borenstein they are 155,000, 75,000, and 50,000 dollars per MW for coal, combined-cycle, and combustion turbine units.

The heat rates for the new combustion turbine and combined-cycle units used in the estimations are the ones provided by Borenstein. Borenstein implicitly assumed the heat rates to be 13,882.35 Btu/kWh for combustion turbine units and 8,000 Btu/kWh for combined-cycle units. Also, Ishii (2004) using world-wide sales data from 1980 to 2001, argues that, for the latter years of his data, the heat rate of combined-cycle turbines seems to be around 8000 Btu/kWh if capacity is limited to 50 MW. The heat rate for the new coal units used in the estimations is an average heat rate of coal units opened in the ERCOT market in the year of 1980 or later. That is, 10,325.68 Btu/kWh.

The estimation allows the system capacity to change whenever entry or exits of new units are expected. A unit is expected to be operating in a given future date if its inauguration happened or is planned to happen before that date and there is no plan of retiring the unit before that date. Only the units under construction or in an early development stage were considered for futures openings.

The estimation allows the fuel prices to change according to the available data for future fuel prices.

In October of 2005, there were 36 plants out of service. Together they represent 6.027% of the total capacity in 2005. For all units, including the new ones, the probability of a break down, at any point in time, is also assumed to be to 6.027%[14].

The future loads were estimated according to the forecasted load growth rates presented in Report on Existing and Potential Electric System Constraints and Needs (ERCOT, 2005). "… ERCOT load forecasters consider a wide range of variables such as population, weather, land usage, general business economy, government policy, and societal trends in terms of both historical actuals and the

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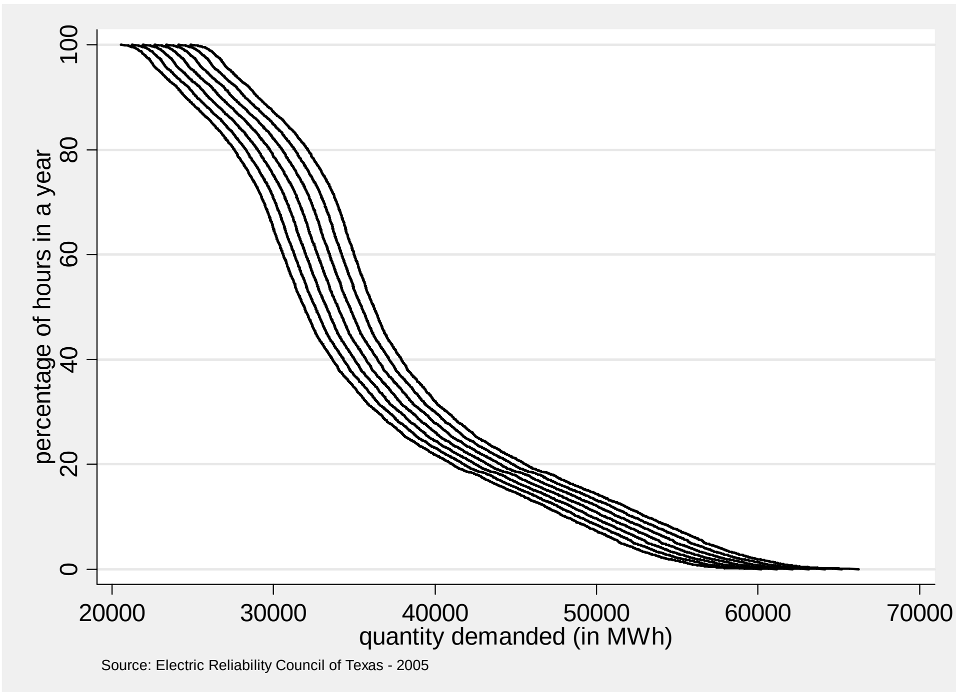
[13] If we assume that the optimal investment is equal to the optimal long run capacity we will obtain an upper bound value for investment and respective efficiency gains, most likely, extremely far from the real values.

[14] Since among the units out of service there are new and old units, it was assumed that the probability of break down is not related to the unit's age. In other words, once built, a new unit has the same probability of a break down as an old unit.

best predicted future indicators available[15].” The report predicts a load increase of 2.1% per year and peak load increase of 1.6% per year until 2011. The forecasted loads are represented in Figure A10[16].

FIGURE A10: 2005's load and forecasted loads from 2006 until 2011.



I calculate the annual surplus of adding (replacing) one unit of a given technology type to the system in January 1st. The benefit generated by this extra unit in a given hour of the year is calculated considering the prices of gas in that month, the price of coal in that year, the demand at that hour and, the units operating at that date. The annual total benefit is calculated adding the benefit generated by the unit at each hour of the considered year, starting in the first hour of January 1st and ending in the last hour of December 31st.

The optimal investment profile in a given year is the investment profile that maximizes the social surplus. The social surplus is equal the summation of the present value of the social surplus provided by the new units for all years they are expected to be operating. Note that there is no restriction about the year the investment will take place. The solution to the maximization problem should specify the optimal investment in each technology for each year. Despite all the eventual difficulties associated with this infinite inter-temporal maximization problem, the

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[15] Energy prices were not mentioned in the report as one of the variables in the load forecast equation. I assumed that the price charged to consumers in the flat rate service will remain constant for all years.

[16] The forecasted load is 1.6% higher than the previous year load (forecasted or realized) plus a constant term. The constant term decreases progressively as the peak load is approached, in a way that the total forecasted load is 2.1% higher than the previous year load.

solution would still require much longer series of expected future fuel prices and load than the ones available.

This paper does not present the optimal investment profile. Instead, for each year, it presents the investment profile[17] that maximizes the social surplus in the corresponding year. The procedure is repeated for all years for which data is available. Presumably, those investment profiles are an indicator of the optimal investment. For instance, suppose that the optimal investment in coal units for the years 2006, 2007, 2008, 2009, 2010 and 2011 are 100, 105, 95, 100, 105 and 110 MW, respectively. It implies that if new coal units with total capacity of 95 MW start operating in 2006 they will provide positive social surplus for at least the following five years. If no drastic changes in the parameters of the model are expected for the next years, 95 MW is probably a lower bound indicator of the optimal investment in coal units.

In the first stage the algorithm calculates the investment in combustion turbine units that maximizes the social surplus in a given year under the assumption that there is no other technology available to receive positive investment. In the second stage some of those units are replaced by combined-cycle gas units if the replacement improves the social surplus in the corresponding year. Finally, in the third stage, some combined-cycle gas units are replaced by coal units. Finding that the investment in a given technology that maximizes the social surplus is zero means that the technology does not belong to the set of technologies qualified to receive positive investment. In this case, the technology should be removed from the set and, the procedure reapplied.

For four possible values of the elasticity demand and for each year from 2006 until 2011, Table 2 presents the investment in coal, combined-cycle gas turbine, and combustion turbine units that maximizes the social surplus in the corresponding year. For all elasticities and years considered, positive investment in combined-cycle gas turbine or combustion turbine units generates a social loss. Only investment in coal units can generate a positive social surplus.

It is possible that a certain investment in coal units provides positive social surplus for all years from 2006 until 2011 although; it is not optimal to build those units in any of those years. It can happen for two reasons. First, because the present value of social loss in later years is larger than the positive social surplus generated by the units. Second, it is possible that the present value of the social surplus can be maximized delaying all or part of the investment. A more strong implication can be inferred if a new unit of a given technology provides a social loss for all years from 2006 until 2011. That is the case of combined-cycle gas turbine and combustion turbine technologies. If at a given date, a unit of a given technology provides a negative surplus in the first year of its operation it implies that it is not optimal to invest in this technology at that date. Even if in the discounted future benefit is greater than the cost of building this unit at that date, the social surplus is maximized postponing the investment.

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[17] The investment profile of a given year does not specify how much money should be invested in each technology in that year but how many additional units of each technology should be operating in January 1st of that year.

Table 2: Investment profile that maximizes social surplus in the corresponding year and respective social surplus.

year	coal (in MWh)	combined cycle (in MWh)	combustion turbine (in MWh)	social surplus per consumer in the corresponding year (in dollars)	social surplus in the corresponding year (in thousands of dollars)
Elasticity = -0.025					
2006	14,720	0	0	133.93	2,678,631
2007	15,532	0	0	137.72	2,754,316
2008	14,542	0	0	113.06	2,261,274
2009	14,011	0	0	93.72	1,874,414
2010	12,731	0	0	63.04	1,260,757
2011	12,327	0	0	43.26	865,225
Elasticity = -0.15					
2006	19,636	0	0	192.57	3,851,322
2007	20,558	0	0	195.78	3,915,623
2008	19,772	0	0	163.52	3,270,373
2009	19,525	0	0	138.12	2,762,433
2010	18,254	0	0	97.98	1,959,611
2011	17,936	0	0	70.32	1,406,461
Elasticity = -0.3					
2006	27,173	0	0	268.64	5,372,882
2007	28,172	0	0	271.04	5,420,770
2008	27,408	0	0	229.42	4,588,319
2009	27,285	0	0	197.06	3,941,107
2010	25,936	0	0	145.83	2,916,668
2011	25,597	0	0	109.64	2,192,742
Elasticity = -0.5					
2006	39,065	0	0	379.71	7,594,231
2007	40,152	0	0	380.89	7,617,804
2008	39,622	0	0	327.96	6,559,220
2009	39,696	0	0	287.80	5,756,021
2010	38,038	0	0	222.93	4,458,697
2011	37,870	0	0	177.00	3,539,981

In conclusion, the results presented in Table 2 imply that it is not optimal to invest in combined-cycle gas turbine or combustion turbine units during the years considered.

Even in the case that there are no other technology available; investment in combustion turbine units can only generate a social loss. Obviously this technology does not belong to the set of technology qualified to receive positive investment. In the next step, combustion turbine is eliminated from the set and the procedure is reapplied. Once again, the optimal investment in combined-cycle gas units is zero and the only technology remaining in the set of technologies qualified to receive positive investment is the technology that uses coal as an input. Independent of the realized investment in coal units the optimal investment in combined-cycle gas turbine or combustion turbine units is zero. Even if new investment in coal units is not allowed, the optimal investment in other technologies remains zero. The absence of investment would imply that the changes in the parameters of the model, like demand increases, should be accommodated by changes in prices.

The fact that it is not optimal to invest in combined-cycle gas turbine or combustion turbine does not imply that the technologies does not belong to the optimal long run composition. It is possible that the system has exactly the optimal level of units for the technologies or an overinvestment happened in the past. A more optimistic scenario about the future prices of gas at the time of the investment decision might have contributed to an eventual overinvestment. Consequently, the substantial investment in combined-cycle gas turbine units in the last years[18] can be evaluated as an overinvestment under current expectations about future fuel prices.

For each elasticity and year, the investment in coal units presented in Table 2 is the investment that maximizes the social surplus in the corresponding year. If additional coal units with total capacity of 12 thousand MW start operating in 2006 they will provide positive social surplus for at least the following five years, even under the assumption of a extremely low demand elasticity of -0.025.

The elasticities -0.025 and -0.15 are intended to capture the consumers' short run reaction to RTP. In the long run, a greater response is expected from consumers. The elasticities -0.3 and -0.5 are intent to capture the long run impact of RTP. Considering the elasticities -0.025 and -0.15, the investment in coal units that would generate positive surplus for all considered years are about 12 and 17 thousand MW, respectively. For the elasticities -0.3 and -0.5 a positive social surplus is obtained for all years considered if the investment in coal units are approximately 25 and 37 thousand MW, respectively. For all years and elasticities considered, Texans can obtain a positive social surplus investing in at least 12 thousand MW.

The optimal investment in coal units depends on several variables. First the expected increase in demand over the years raises the benefit of investing in coal units. The expected decrease in gas prices[19] reduces the marginal cost of the gas units currently operating making the investment in infra-marginal units, like coal units, less attractive. The expected increase in coal prices reduces the gain of replacing more expensive units currently operating for coal units. Entry of new units can reduce the optimal investment in coal units. Exit of units can increase it. Those variables affect the optimal investment in different directions. Moreover, some of those variables do not follow a smooth or continuous pattern. Entries and exits, for instance, represent one time change.

Despite of all the expected changes in the variables that determine the investment in coal units from 2006 until 2011[20], once a elasticity is selected, the investment in coal units that maximizes the social surplus in a given year does not change drastically from one year to another. So, if no huge changes in the variables that determine the investment in coal units is expected for the years following 2011, it is possible that the figures presented in Table 2 represent a reasonable indicator of the optimal investment in coal units at the present date.

Charging the RTP from consumers would improve the social surplus for two reasons. First, it maximizes the social surplus given the current capacity installed. Second, assuming that electricity suppliers are price takers, the RTP system would induce the realization of the optimal investment. The social surplus in Table 2

[18] See Figure A8.
[19] See Figure A2.
[20] Specially the changes in the future fuel prices. See Figure A2.

intends to represent an estimative of the second impact. For each investment profile in Table 2, the last two columns present the associated social surplus and social surplus per consumer obtained in the corresponding year. For the elasticities -0.3 and -0.5, efficiency gains range from approximately 2,192 to 7,617 million dollars per year. For the same elasticities, implementation of the investment profile in Table 2 would generate a surplus between 109 and 380 dollars per consumer a year[21]. Assuming the elasticity of -0.3 the social surplus ranges from about 2,192 to 5,420 million a year depending on the year. For the elasticity of -0.5 it ranges from about 3,539 to 7,617 million.

Table 3 presents the proposed investments after 2005. Comparison of the results in Table 2, suggests that some underinvestment may be occurring in the ERCOT system; also, a tendency to invest in coal and other baseload units as the investment profile in Table 2 would imply.

Table 3: Total capacity (in MW) of proposed and new units after 2005

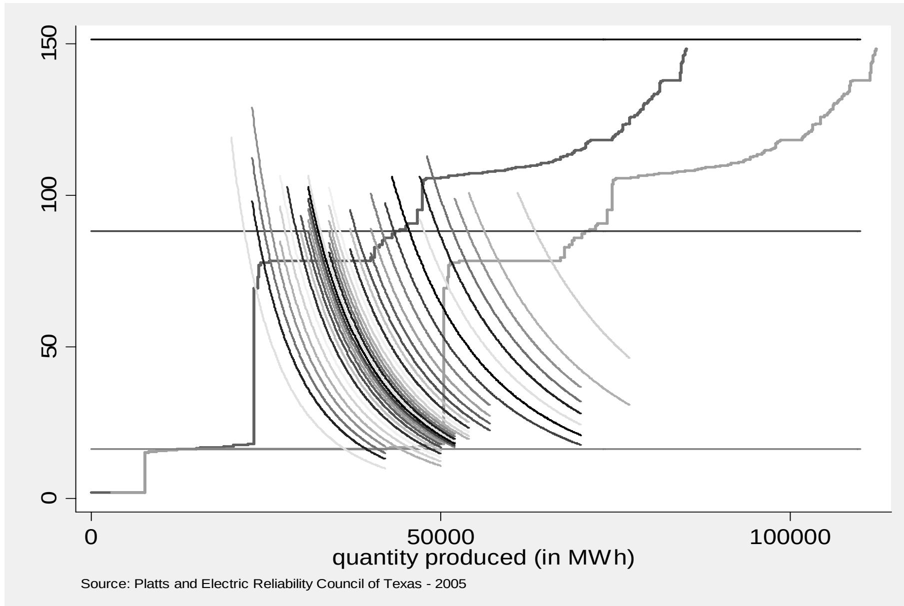
Proposed						
	2006	2007	2010	2011	2050	Total
Steam & Lignite (coal)	-	-	1,720	600	-	2,320
Steam & Coal	-	-	550	-	-	550
Wind	298	160	-	-	-	458
others	24	-	-	-	-	24
Total	**322**	**160**	**2,270**	**600**	**0**	**3,352**
Early development						
	2006	2007	2010	2011	2050	Total
Steam & Coal	-	-	750	-	800	1,550
Steam & PetCoke	-	-	-	-	300	300
Gas Turb & Natural Gas	100	-	-	-	-	100
others	-	-	-	-	20	20
Total	**100**	**0**	**750**	**0**	**1,120**	**1,970**
New units under construction						
	2006	2007	2010	2011	2050	Total
Combined Cycle & Natural Gas	820	-	-	-	-	820
Steam & Natural Gas	50	-	-	-	-	50
others	-	2	-	-	-	2
Total	**870**	**2**	**0**	**0**	**0**	**872**

Source: Platts, 2005

Figure A11 presents the demand curves for elasticity of -0.3 and the marginal cost curve in January of 2006 before and after the optimal investment is realized. The horizontal lines in Figure A11 represent the marginal cost in January of 2006 for the three technologies qualified to receive positive investments.

21 According to ERCOT annual report there are approximately 20 million consumers in the ERCOT market.

FIGURE A11: System's marginal cost curve in January of 2006, system's marginal cost curve after investing the optimal amount and some estimated demand curves. The demand curves were estimated assuming elasticity of -0.3.



6. Carbon emission market

According to The Wall Street Journal[22], "Power plants produce 39% of U.S. carbon-dioxide [a green house gas] emissions, and four-fifths of that amount comes from coal-fired plants. Texas is responsible for 10% of the nation's total, more than any other state."

Electricity generators cause a negative externality emitting carbon-dioxide. In a competitive market, the optimal outcome can be achieved by charging the Pigouvian Tax from generators. In equilibrium, the Pigouvian Tax is equal to the social cost of having an extra marginal amount of CO_2 in the atmosphere. Since there is no objective way to identify the social cost in this case, this section presents an exercise that attempts to provide a rough indicator of the sensibility of the results presented in Table 2 to the establishment of a carbon emission market.

The marginal cost of a gas or coal unit, already installed or considered for investment, is calculated according to the equation

$$\text{MC} = \text{original MC} + [\text{carbon emission factor (in tonne/Btu)}] \times [\text{heat rate (in Btu/MW)}] \times [\text{carbon allowance's price (in dollar/tonne)}].$$

Data for 2004's carbon emission factors are provided in the Energy Information Administration webpage[23]. For natural gas, the factor is 116.97 pounds

22 As Emission Restrictions Loom, Texas Utility Bets Big on Coal" by Rebecca Smith; July, 21st of 2006.

23 See http://www.eia.doe.gov/cneaf/electricity/epa/epata1p3.html. Released in November, 2005.

of CO_2 per million btus. The relevant factors for coal units are 205.45, 212.58 and, 215.53 pounds of CO_2 per million btus for bituminous, sub-bituminous and lignite, respectively.

As an exercise, I assume two possible price levels for carbon allowances. The first price level is set equal to the average future price of carbon allowances in the EU market from 2006 until 2011. That is, 18.29 €/tonne of CO_2[24] or 23.44 US$/tonne of CO_2[25]. The second price level is equal to the first price level multiplied by two, i.e., 46.88 US$/tonne of CO_2.

Table 4: Investment profile that maximizes social surplus in the corresponding year and respective social surplus assuming the price of carbon allowance of 23.44 US$/tonne of CO_2.

year	coal (in MWh)	combined cycle (in MWh)	combustion turbine (in MWh)	social surplus per consumer in the corresponding year (in dollars)	social surplus in the corresponding year (in thousands of dollars)
			Elasticity = -0.025		
2006	12,147	0	0	77.66	1,553,106
2007	12,797	0	0	77.21	1,544,113
2008	11,651	0	0	52.44	1,048,725
2009	10,819	0	0	32.53	650,676
2010	7,296	0	0	8.45	168,967
2011	0	0	0	0.00	0
			Elasticity = -0.15		
2006	14,521	0	0	97.31	1,946,169
2007	15,251	0	0	96.11	1,922,221
2008	14,190	0	0	67.15	1,342,932
2009	13,405	0	0	43.47	869,465
2010	9,860	0	0	13.75	275,014
2011	1,383	0	0	0.16	3,220
			Elasticity = -0.3		
2006	17,803	0	0	122.12	2,442,456
2007	18,594	0	0	119.85	2,396,936
2008	17,567	0	0	85.80	1,716,019
2009	16,758	0	0	57.81	1,156,113
2010	13,173	0	0	21.56	431,224
2011	4,891	0	0	2.08	41,653
			Elasticity = -0.5		
2006	22,736	0	0	156.99	3,139,807
2007	23,673	0	0	153.30	3,065,927
2008	22,530	0	0	112.60	2,251,927
2009	21,669	0	0	79.42	1,588,400
2010	17,993	0	0	35.25	705,098
2011	9,895	0	0	9.24	184,846

24 In September, 6th of 2006, the annual future prices posted on the energy exchange website http://www.eex.de/index.php were 16.59, 17.08, 18.13, 18.63, 19.32 and, 19.97 €/tonne of CO_2 for all years from 2006 until 2011. Those prices are similar to the ones available in a leading platform for carbon emissions trading, http://www.ecxeurope.com. Since the future volumes are not available, I calculated a simple mean for all years.

25 The Wall Street Journal exchange rate in the edition of September, 6th of 2006 was 1.282 US$/€.

Table 5: Investment profile that maximizes social surplus in the corresponding year and respective social surplus assuming the price of carbon allowance of 46.88 US$/tonne of CO_2.

year	coal (in MWh)	combined cycle (in MWh)	combustion turbine (in MWh)	social surplus per consumer in the corresponding year (in dollars)	social surplus in the corresponding year (in thousands of dollars)
Elasticity = -0.025					
2006	9,149	0	0	30.33	606,678
2007	9,491	0	0	26.28	525,632
2008	5,913	0	0	5.55	110,967
2009	0	0	0	0.00	0
2010	0	0	0	0.00	0
2011	0	0	0	0.00	0
Elasticity = -0.15					
2006	10,022	0	0	33.22	664,429
2007	10,329	0	0	28.50	570,088
2008	6,534	0	0	6.46	129,105
2009	0	0	0	0.00	0
2010	0	0	0	0.00	0
2011	0	0	0	0.00	0
Elasticity = -0.3					
2006	11,130	0	0	36.82	736,382
2007	11,483	0	0	31.26	625,126
2008	7,345	0	0	7.55	151,011
2009	0	0	0	0.00	0
2010	0	0	0	0.00	0
2011	0	0	0	0.00	0
Elasticity = -0.5					
2006	12,744	0	0	41.83	836,517
2007	13,115	0	0	35.16	703,110
2008	8,525	0	0	9.06	181,172
2009	0	0	0	0.00	0
2010	0	0	0	0.00	0
2011	0	0	0	0.00	0

Table 4 and 5 present the investment profiles that maximizes the social surplus in each corresponding year assuming the carbon allowances price of 23.44 and 46.88 US$/tonne of CO_2, respectively. Obviously, it is not optimal to invest in combined cycle or combustion turbine units. The results presented in the previous section, Table 2, imply that it is not optimal to invest in gas units even if investment in coal units is not possible. An upward shift of the marginal cost curve and increase in the marginal cost of gas units can only reduce the social surplus associated to an investment in those units. Therefore, the optimal investment in gas units cannot be positive after the introduction of carbon emission costs.

The investment in coal units that maximizes social surplus drops significantly with the introduction of carbon emission costs. The corresponding social surpluses drop even more.

For any demand curve, the social surplus of an extra coal unit is given by the area between the marginal cost curves before and after adding the extra unit to the system that lies below the demand curve. Consideration of carbon emission costs causes an upward shift of the marginal cost curve. First, imagine a parallel upward shift. Considering or not carbon emission costs, the area between the marginal cost curves before and after the addition of one coal unit to the system is the same but, for each demand curve, the area between the marginal cost curves that lies below the demand curve is smaller for the upward-shifted marginal cost curves. Therefore, introduction of carbon emission costs reduces the social surplus of an extra coal unit and, consequently, decreased the investment that maximizes social surplus. The impact is even greater because the upward shift in the marginal cost curve is not parallel. The marginal cost of coal units increased more than the marginal cost of gas units after the introduction of carbon emission costs.

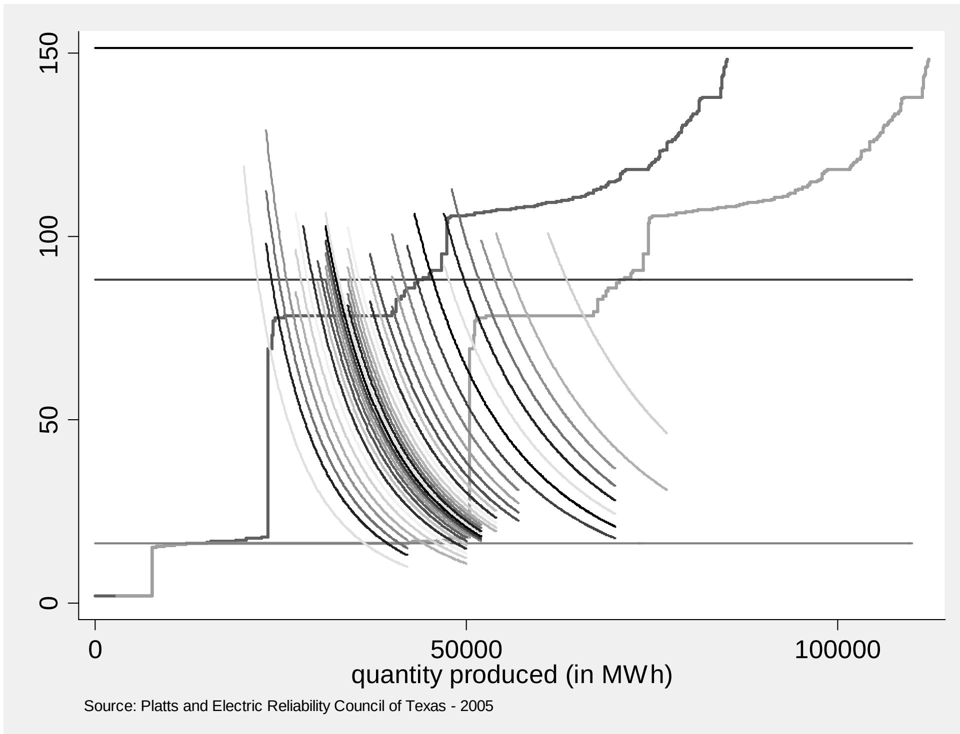
On average, over the years, the low segment of the marginal cost curve is shifting upward because of the increase in coal's price and; the higher segments are shifting downward because of the decrease in gas's price.

Everything else kept constant, this continuous increase in the low segment and decrease of the high segments of the marginal cost curve will reduce the social surplus associated to extra coal units. Consequently, the investment that maximizes the social surplus decreases over the years. The factors that contributed to make the estimated investment slightly smaller for later years in Table 2, have their impact magnified with higher carbon allowances costs, causing a substantial dispersion between the investment that maximizes the social surplus over the years considered. In particular, for the higher price of carbon allowances, 46.88 US$/tonne of CO_2, the investment that maximizes social surplus drops to zero in the last three years considered in the estimations. This result is not surprising. Note from Figure A11 that for most demand curves, the social surplus of adding the first extra coal unit to the system is mainly determined by the first tall rectangle between the marginal cost curves before and after adding the extra unit.

Besides, the social surplus of adding the first coal unit to the system is extremely similar to the social surplus of adding the second coal unit to the system. In fact, the social surplus of extra coal units does not change much until the system's marginal cost curve start crossing the demand curves around the point in which they are highly concentrated. At this point, for an increasing number of demand curves, the tall rectangle between the two marginal cost curves, before and after the addition of one extra coal unit, no longer lies below the demand curve. Until the system reaches the point in which the demand curves are highly concentrated, the social surplus associated to the first extra coal unit is similar to the social surplus of the second extra unit and, so on. Therefore, if it is welfare enhancing to invest in one extra coal unit, it is welfare enhancing to invest in several units. That is also the reason of the sudden drop in the investment that maximizes the social surplus from 2010 to 2011 for the lower price of carbon allowances and elasticity -0.025.

For the carbon allowance price of 23.44 US$/tonne of CO_2, the investment in coal units that generate positive social surplus for all years considered, in MW, are zero, 1,383, 4,891 and 9,895 for the elasticities 0.025, 0.15, 0.3 and 0.5, respectively. For the carbon allowance price of 46.88 US$/tonne of CO_2, no positive investment in coal units generates positive social surplus for all years considered.

FIGURE A11: System's marginal cost curve in January of 2006, system's marginal cost curve after investing the optimal amount and some estimated demand curves. The demand curves were estimated assuming elasticity of -0.3.



Consideration of carbon emission costs introduced a greater variability of the results to changes in the parameters of the model. If the parameters experience changes of the same magnitude for the years following 2011, the investment profile that maximizes social surplus in subsequent years can be very different from the investment profile obtained for the years from 2006 until 2011. The sensibility of the results to changes in the parameters of the model, compromise attempts to predict the optimal investment based on the results from 2006 until 2011. Nevertheless, one can argue that the increase in the expected price of coal and the stabilization of the expected price of gas after 2011 (see Figure A2) will contribute to reduce the investment that maximizes social surplus for a few years following 2011.

7. CONCLUSION

The paper presents investment profiles in electricity generation that provides positive social surplus for every year from 2006 to 2011. During the covered period it is not optimal to invest in combined cycle or combustion turbine units. The investment in coal units that generate positive social surplus for all years considered ranges from about 12 to 37 thousand MW depending on the assumption about demand elasticity. The associated efficiency gains lie between, approximately, 43 and 177 dollars per consumer a year. Once the social costs associated to carbon emission are considered, the investment in coal units that maximizes social surplus drops substantially. For the carbon allowance price of two times the level in Europe, the optimal investment in coal units is zero. Consideration of carbon emission costs does not transform cycle or combustion turbine technologies in attractive technologies for investment.

One limitation of the paper is that the starting up cost, the cost that each unit faces when it is turned on, is assumed to be zero. Another limitation is that demand and costs are assumed to be known with certainly.

Only three technologies qualified to receive positive investment are considered. According to Borenstein (2005a), they represent three technology types: baseload, mid-merit, and peak. Under this interpretation, the results presented represent the estimated investments that generates positive social surplus for three classes of technology. The most informative estimation would specify the optimal investment range for all technologies qualified to receive positive investment. However, such detailed result demands an estimation of the annual capital cost for all technologies qualified to receive positive investment.

Significant investment in coal units would most likely change the future prices of fuels and, consequently, the optimal investment. Instead of modeling price of fuels as a function of the investment, it was assumed that the future prices of fuel would remain constant for all investment levels.

The cost of achieving the optimal outcome is assumed to be zero. It is possible that the benefit of implementing the optimal investment does not pay its cost. A perfectly competitive market implies charging the Real Time Price (RTP) from all consumers. The society cost of adopting the RTP includes the cost of measuring consumption in short time intervals, the consumer's costs of constantly checking prices and, the disutility generated by the introduction of uncertainty about future prices. If this cost is significant, maximization of the social welfare may point to some variation of the time-of-use (TOU)[26] approach that, although, does not generate the efficient investment, is cheaper to implement.

An interesting topic for future work would be to measure the performance in terms of efficiency of the alternative TOU rates. To estimate the magnitude of the gap between expected and optimal investment under alternatives TOU rates; and the welfare loss implied by this gap. In other words, what share of the social welfare that the optimal investment would yield can be captured by adopting specific TOU rates. If RTP is an unattainable solution or costly to implement, maximization of the social welfare in the long run demands knowledge about the relative performance of alternative price approaches in terms of optimal investment.

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[26] The TOU rates consist of the pre-established rates that differ depending on the season of the year, day of the week, and time of the day. There are many possible rates for different TOU periods. Even imposing revenue neutrality, one is still left with several rates. Borenstein (2005b) suggests some TOU rates that satisfy some extra conditions like no cross-subsidies among consumers.

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