# Buying an Option to Build: Regulatory Uncertainty and the Development of New Electric Generation

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**Introduction**

The electricity industry is in the midst of fundamental change as a result of federal and state (or provincial) efforts to restructure the industry, thereby introducing and increasing the intensity of competition in wholesale and retail markets (Borenstein et al., 2002; Joskow, 2000; Littlechild, 2000; Stoft, 2002; Wolfram, 1999). One key feature of restructuring has been a move away from centralized planning, wherein utilities, in conjunction with state public utilities commissions, planned for development of new generating capacity and transmission upgrades in order to meet expected increases in future demand. In its place, a decentralized process of development and investment decisions—largely by non-utility companies—is evolving; Ishii and Yan (2002), for example, analyze the "make or buy" decision faced by independent power producers in the deregulated U.S. wholesale power market. Unlike the rate-regulated regime of the past, the development and investment plans of these myriad companies are not subject to approval of public utilities commissions, nor are they coordinated in any way by a central body. This is particularly true in states that have aggressively pursued retail restructuring—sometimes requiring or encouraging their utilities to divest generating resources—but it is also the case in other states to the degree that non-utilities find it attractive to develop new generating resources in those states.

Under restructuring, states will no longer oversee the entire process of development and investment in new generating capacity. However, state entities still wield significant power to influence investments through licensing and permitting processes, through the terms of interconnection agreements, and more generally, through state decisions regarding whether and how far to pursue restructuring of their retail markets. Specifically, state and local agencies responsible for air and water quality and land use decisions must grant approval for companies to begin construction or operation of new power plants. The role of these agencies is to ensure that any new development is in compliance with relevant laws, ordinances, and regulations. There is considerable variation across states in the administration of the development process and thereby in the costs developers must incur to gain approval from state and local entities.

Federal environmental laws and regulations, as well as laws protecting endangered species also play a role in determining where and how new power plants are built. For example, proposed new power plants in any area that is not in compliance with EPA air quality regulations are subject to "new source review," requiring plant owners to purchase or otherwise acquire air emission credits equal to or in excess of their planned emissions. Often the new source review permits are issued by state agencies that have gained approval from the EPA to grant such permits. In the event that a proposed new power plant might impinge on the habitat of an endangered species, developers must also get approval from other federal and state agencies.

The costs of early development—the so-called soft development costs incurred prior to breaking ground for construction—are a small fraction of total costs to build but they are significant in magnitude, running between several hundred thousand and many millions of dollars. The magnitude of these soft development costs depends on the characteristics of the site, specific state and local requirements, and on how long the regulatory approval process takes—something that varies widely across states. For example, in a report on new generation development in three states, the U.S. General Accounting Office (2002) found that the average number of months required to gain state approval to cite a large power plant—defined as a plant with greater than 200 MWs of generating capacity—required about 8 months in Texas, 13 months in Pennsylvania, and 14 months in California. These soft development costs reflect the cost to developers of acquiring an option to build a power plant.

In addition to the development costs associated with acquiring regulatory approval, new power plants must be interconnected with the transmission grid, frequently requiring costly upgrades to the system to maintain reliability. The terms under which these new power plants are allowed to interconnect and the distribution of the costs of upgrades is another critical factor that determines where and when power plants are built. Again, there is considerable variation across states in the interconnection costs, and a developer's share of these interconnection costs can run from a few hundred thousand to tens of millions of dollars, depending on the characteristics of the existing transmission system and on how the costs are assessed.

Many hazards lurk in the regulatory arena. Because the development process can be long—running to many years in some cases—regulatory and market conditions may change considerably, causing developers to reassess the relative merits of each of their projects. Abrupt changes in regulatory environments can cause developers to flee. For example, during 2000 and 2001, high electricity prices and projections of future high prices in California, led to a flurry of new development projects in that state. Subsequently, California suspended its retail competition and required all consumers to buy from the state's utilities at regulated rates. Since the state's suspension of retail competition and the renegotiation of long-term contracts entered into in the winter and spring of 2001, most of the proposed projects have been cancelled or postponed, and currently, very little new development is taking place in the state. It should be noted that California's

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suspension of retail competition was necessary in order to ensure that the state utilities could charge prices high enough to recover the costs of power purchased by the state at high prices during the height of the electricity crisis. These prices are considerably higher than current or expected future wholesale prices in the state.

Market uncertainty also adds to the risk of committing development resources. Energy prices have proven to be quite volatile across regions and over time. Market and regulatory uncertainty interact because longer or less certain approval processes to build new power plants or associated transmission upgrades increase developers exposure to market risk. Conversely, when development is delayed or abandoned because of regulatory uncertainty the resulting supply shortfalls can lead to greater price volatility. In the next section we explore the decision making process of power plant developers. In the remainder of the paper we examine the experiences of states in attracting new generation development, the types of generators being built, and the actions of states vis-à-vis restructuring.

**New Generation Development**

Power plant developers look for the highest return on their investment, conditional on the risk of their portfolio of projects. In order to mitigate the risk across regulatory jurisdictions and over time, power plant developers may diversify their investments across regions and states, and across power plant type and fuel sources. In addition, because the regulatory approval process is long and outcomes uncertain, developers often plan multiple options for a given development budget—"real options" in the parlance of Dixit and Pindyck (1994). As more information is revealed about the future prospects at different sites, options are abandoned sequentially until eventually, only projects that will be completed remain.

Developers compete to build power plants in the right locations and at the right time to meet expected demand. Suitable locations generally require a nexus of access to fuel sources, transmission lines, and water for cooling. For example, developers of natural gas fired power plants—the predominant technology being built in recent years—look for sites with access to high volume gas pipelines with excess capacity. Similarly, coal fired plants need access to rail lines, or direct access to coal at the source.

Access to transmission suitable for interconnection is critical for developers. The costs to developers of gaining transmission interconnection vary from hundreds of thousands of dollars to hundreds of millions depending on the location of the new power plant, the effects of adding generating capacity on the entire system, and on how the costs are assessed. The terms under which interconnection is approved vary a great deal across states and control areas as do the distribution of upgrade costs. For example, in Texas upgrades required to interconnect new power plants are paid for through a surcharge on electricity sold to all consumers, while in California, developers have been required to pay for any upgrades deemed necessary by the local transmission owner—generally a local utility company.

The implications of different approaches to assessing interconnection costs on power plant location can be profound. When the costs are borne by consumers, developers can focus more on finding locations with lower development costs, easier access to fuel sources, and water for cooling. It is also possible under these conditions that there will be over-building of transmission upgrades, because developers do not bear the costs of any negative externalities they impose on other grid users when adding generating capacity at a point increases transmission congestion, thereby limiting incumbent generating plants' outputs. In addition, this approach may lead to concentration of generating units at some distance from the load it serves, because land costs may be lower and environmental issues, such as air quality, less prevalent on such sites.

On the other hand, when developers bear the full cost of upgrades, they look for sites with lower interconnection costs, which—given the nature of the flow of electricity and of congestion in the existing transmission grid—may encourage development closer to the load it will serve. However, it may cause under-building of upgrades because the developers are not compensated for any positive externalities accruing to electricity consumers. From the perspective of efficiency, the ideal is to assess upgrade costs on developers in the amount equal to the negative externalities imposed on other transmission users, and assess costs on consumers in the amount that they benefit from the new capacity. In practice, there is a great deal of uncertainty about the value of either externality, but it is fairly clear that neither extreme—assessing all costs to consumers or all costs to developers—is optimal except under extreme conditions.

Cooling water is essential for many of the most commonly built power plants. For the most part, this requires locating near a source of fresh water, although some designs allow the use of waste water. The volume of water drawn by power plants in the United States is quite large, ranking second only to agriculture. The water-cooling processes used in most newer power plants loses less water to steam in the atmosphere than do older technologies—most of the water is recaptured and returned to its source. However, returning warmer water to a fresh source can have negative environmental implications, and these issues have led to controversy and delays or denials of permits in some cases.

Finally, developers and investment bankers also prefer, other things equal, stable regulatory jurisdictions and clear market rules for trading electricity. Very few states have established and maintained clear paths to retail restructuring and this creates regulatory uncertainty. Specifically, only 17 of the 50 states and the District of Columbia have enacted and implemented legislation allowing consumers to choose their retail electricity provider. Even among the states with retail choice programs, the states have simultaneously reduced and frozen retail rates at levels that have discouraged retail competition. A lack of retail competition also feeds back into the development of new capacity by limiting the ability of developers to enter into long-term supplier contracts with large consumers or multiple retail sellers. At the federal level, there has been a great deal of regulatory uncertainty caused by a lack of consensus among legislators and regulators about the scope and pace of competitive measures in wholesale power markets and with regard to electricity transmission.

**Data Source and Construction of Sample**

The data used in this paper are compiled primarily from monthly reports of the NewGen database published by RDI, a division of Platts. RDI gathers data on new generation projects from trade publications and state and federal data sources and reports the status of each of the projects they identify as of the reporting month. These new projects include upgrades and incremental additions to existing power plants—as in the case of nuclear plants—as well as completely new power plants. The status reports identify projects as being in one of six categories—proposed/early development, advanced development, under construction, operating, tabled, or canceled. A seventh category applies to projects that are being retired. We are only dealing with gross additions to generation in this paper because we are focusing on how projects transition from one status to the next, and retirements do not transition through the status categories in the same way as new generation projects. For the purposes of this paper, we define a project as a unique power generating plant that could be completed independently of any other units. Projects progress through the stages of early development, advanced development, construction, and finally operation. Projects may also be tabled or cancelled at any point in the process. In making the individual power generating plant the unit followed through time, we diverge from the definition of project adopted by RDI.

The NewGen database is designed to present a cross-sectional snapshot of the development of new generating facilities each month. As such, RDI does not publish historical time series of the status of projects. Instead, each monthly edition of the NewGen database supplants the previous month, in which newly identified projects are added and projects that have been in the operating or the cancelled status for over a year are removed. In addition, correction of errors, discovered in a given month, are not corrected in previous months of the database. Therefore, in order to develop such a panel of new generation projects, we accumulated individual monthly reports and merged them by a unique project identifier. This identifier combined information about the type of generating unit under development, the expected date of completion, the primary fuel of the unit, and other fields defined by RDI. Changes by RDI recorded in later months had to be traced back to past months to make sure the series were accurate. For example, a proposed project to build a 1000 MW capacity combined cycle natural gas plant may have been announced in the trade press and be listed by RDI that month as proposed. Subsequently, RDI may have received information from another source that the project is actually comprised of two separate combined cycle generating plants, each of 500 MW capacity and that these two units have different expected completion dates. Henceforth, this project would be divided into two phases by RDI, but would still be listed as a single project in previous months. There-

**Table 1**
**New Projects by Owner Type, Jurisdiction, and EIA Restructuring Status**

| State | Status | Non-Utility | Utility | State | Status | Non Utility | Utility |
|---|---|---|---|---|---|---|---|
| AB | n.a. | 40 | 6 | NB | n.a. | 2 | 2 |
| AL | Not Active | 23 | 9 | NC | Not Active | 10 | 8 |
| AR | Delayed | 19 | 3 | ND | Not Active | 2 | 2 |
| AZ | Active | 36 | 15 | NE | Not Active | 0 | 12 |
| BC | n.a. | 14 | 5 | NF | n.a. | 1 | 8 |
| BJ | n.a. | 9 | 3 | NH | Active | 3 | 0 |
| CA | Suspended | 193 | 22 | NJ | Active | 19 | 0 |
| CH | n.a. | 3 | 0 | NM | Delayed | 23 | 6 |
| CO | Not Active | 20 | 10 | NS | n.a. | 1 | 2 |
| CT | Active | 14 | 1 | NV | Delayed | 29 | 2 |
| DC | Active | 1 | 0 | NY | Active | 50 | 22 |
| DE | Active | 7 | 2 | OH | Active | 50 | 16 |
| FL | Not Active | 51 | 41 | OK | Delayed | 24 | 6 |
| GA | Not Active | 36 | 11 | ON | n.a. | 22 | 4 |
| IA | Not Active | 10 | 7 | OR | Active | 20 | 5 |
| ID | Not Active | 8 | 2 | PA | Active | 51 | 5 |
| IL | Active | 105 | 13 | PQ | n.a. | 3 | 11 |
| IN | Not Active | 37 | 11 | RI | Active | 3 | 0 |
| KS | Not Active | 6 | 7 | SC | Not Active | 12 | 8 |
| KY | Not Active | 28 | 10 | SD | Not Active | 5 | 4 |
| LA | Not Active | 39 | 6 | SK | n.a. | 2 | 1 |
| MA | Active | 21 | 2 | TN | Not Active | 18 | 13 |
| MB | n.a. | 0 | 1 | TX | Active | 114 | 15 |
| MD | Active | 11 | 2 | UT | Not Active | 6 | 13 |
| ME | Active | 9 | 0 | VA | Active | 36 | 6 |
| MI | Active | 34 | 7 | VT | Not Active | 3 | 2 |
| MN | Not Active | 18 | 11 | WA | Not Active | 38 | 11 |
| MO | Not Active | 10 | 14 | WI | Not Active | 29 | 16 |
| MS | Not Active | 23 | 7 | WV | Delayed | 14 | 1 |
| MT | Delayed | 22 | 2 | WY | Not Active | 14 | 1 |
| MX | n.a. | 16 | 8 | Total | | 1467 | 440 |

fore, we had to correct past monthly entries whenever we discovered such a correction in information for later months.[1] The adjustments and deletions described above resulted in 1,907 unique projects with complete cases that we follow over the thirty-month interval.

**Descriptive Overview of New Projects**

Table 1 shows a tabulation by state/provincial jurisdiction of new projects that were owned by non-utility or utility companies and according to Energy Information Administration designations of state restructuring status. Overall, 77% of the new projects were owned by non-utility companies and 23% by utilities, with considerable variation across jurisdictions ranging from 90% of new projects being non-utility in California to 79% of new projects being utility-affiliated in Quebec. Note that restructuring status is only applicable to states in the United States. We include Canadian and Mexico because there is considerable trade of electricity between these regions and the United States.

Table 2 shows a tabulation of new projects by plant type and whether the projects are non-utility generation or utility generation. About 71% of all new projects are of the combustion turbine or combined cycle types accounting for 78% of the entire generating capacity of all new projects. Also, approximately 80% of these combined cycle and combustion turbine projects are owned by non-utility companies. Table 2 also shows that non-utility development is responsible for the bulk of renewable fuel generation. Specifically, non-utility companies account for 86% of the projects involving geothermal, solar, waste, or wind, and 52% of hydroelectric projects. The table also illustrates the predominance of natural gas as fuel source in new power plant development. The categories "Combined Cycle" and "Combustion Turbine", accounting for 78% of generating capacity under development, use natural gas as fuel source almost exclusively.

Table 3 shows that the majority of development projects

**Table 2**
**New Projects by Owner Type, Plant Type, and Capacity**

| Plant Type | Non-Utility | Utility | Total | sum(cap.) | mean(cap.) |
|---|---|---|---|---|---|
| CC/Cogen | 55 | 6 | 61 | 27897.1 | 457.33 |
| CT/Cogen | 54 | 6 | 60 | 9382.98 | 156.38 |
| Coal | 71 | 34 | 105 | 70931.74 | 675.54 |
| CoalCogen | 5 | 1 | 6 | 2117 | 352.83 |
| CombCycle | 471 | 89 | 560 | 356317.1 | 636.28 |
| CombustTurb | 587 | 207 | 794.4 | 210340.3 | 264.91 |
| Geothermal | 8 | 1 | 9 | 1026.9 | 114.1 |
| Hydro | 28 | 26 | 54 | 13811.45 | 255.77 |
| InternCombust | 16 | 11 | 27 | 674.45 | 24.98 |
| Nuclear | 7 | 23 | 30 | 10603.7 | 353.46 |
| Other Boiler | 25 | 13 | 38 | 8157.42 | 214.67 |
| Solar | 13 | 6 | 19 | 15.14 | 0.8 |
| Waste | 20 | 1 | 21 | 214.59 | 10.22 |
| Wind | 107 | 16 | 123 | 11682.21 | 94.98 |
| Total | 1467 | 440 | 1907 | 723172 | 379.2197 |

[1] See footnotes at end of text.

have been in states that restructured—this includes California, which has recently suspended retail choice, but still has a centralized wholesale market run now by the California Independent System Operator. When we include states that delayed restructuring—states that passed some sort of restructuring legislation, but then delayed its implementation—61% of all projects under development have been in states that took some actions that signaled restructuring plans, compared to states that have been inactive entirely. In part this may be explained by the fact that the states taking restructuring actions generally had higher retail rates to begin with. For this reason, the value of additional units was greater in these states than in the inactive states. However, this is not the whole story. The ability of private generators to make money depends on restructuring status, because a state that allows retail competition will have more potential buyers of power than a state that still relies on a monopoly utility structure at the retail level. In addition, state actions to restructure signal intent on the part of state legislators and regulators to develop competitive electricity markets, making these states more desirable for non-utility investors. The bulk of utility development is in states that took no restructuring steps. Specifically, utilities accounted for 35% of total projects under

**Table 3**
**Projects by Plant Type, Restructuring Status and Owner Entity**

| | Non-Utility Projects by EIA Restructuring Status | | | |
|---|---|---|---|---|
| Plant Type | Active | Delayed | Not Active | Suspended |
| CC/Cogen | 18 | 5 | 18 | 3 |
| CT/Cogen | 21 | 3 | 16 | 4 |
| Coal | 16 | 16 | 36 | 1 |
| CoalCogen | 3 | 1 | 1 | |
| CombCycle | 222 | 50 | 136 | 36 |
| CombustTurb | 225 | 34 | 194 | 115 |
| Geothermal | 1 | 1 | 5 | |
| Hydro | 3 | 3 | 7 | 1 |
| InternCombust | 2 | 3 | 4 | 6 |
| Nuclear | 7 | | | |
| OtherBoiler | 4 | 1 | 6 | 5 |
| Solar | 4 | 1 | 8 | |
| Waste | 12 | 4 | 4 | |
| Wind | 46 | 13 | 24 | 5 |

| | Utility Projects by EIA Restructuring Status | | | |
|---|---|---|---|---|
| Plant Type | Active | Delayed | Not Active | Suspended |
| CC/Cogen | 2 | 1 | 3 | |
| CT/Cogen | 1 | 4 | | |
| Coal | 6 | 1 | 23 | |
| CoalCogen | 1 | | | |
| CombCycle | 16 | 5 | 47 | 6 |
| CombustTurb | 61 | 10 | 120 | 11 |
| Geothermal | | | | |
| Hydro | 1 | 1 | 2 | 1 |
| InternCombust | 10 | 1 | | |
| Nuclear | 11 | 1 | 9 | 1 |
| OtherBoiler | 5 | 1 | 5 | 2 |
| Solar | 6 | | | |
| Waste | 1 | | | |
| Wind | 2 | 11 | | |

development in states that did not pursue restructuring, but only accounted for 14% of projects in states that were either actively pursuing restructuring or had delayed their restructuring implementation.

Finally, Table 4 illustrates the real options nature of power plant development. For example, for non-utility owned projects, over 25 percent of the projects in the sample were cancelled or postponed indefinitely by the last month in the sample period. Another 23 percent of the projects in the sample had been completed and were operating during the last sample month, and the remaining projects were at various other stages of development. This pattern is consistent with developers treating each project under development as an option to build that will be continually evaluated in light of changing regulatory and market environments. Over time, as more information is revealed about the relative values of various options, developers abandon the less valuable projects. Table 4 also shows an apparent difference between utility and non-utility development of new generation. For example, only about 13 percent of the utility owned projects had been cancelled or postponed at the end of the sample period while about 43 percent were operating. This difference between ownership types is also consistent with the view that early power plant development reflects an option to build rather than a firm plan. Utility owners are typically building projects to meet load requirements in their service areas where they are quite familiar with the market and regulatory history. In contrast, non-utility developers may look for opportunities to build in many different regulatory jurisdictions and across very different markets leading to greater regulatory and market uncertainty. Greater uncertainty increases the value of the option to build and should lead to a greater proportion of project starts that end in cancellation or postponement.[2]

**Table 4**
**Status of New Projects at End of Sample Period**

| Status | Non-utility | Utility | Total |
|---|---|---|---|
| EarlyDevelop | 274 | 68 | 342 |
| AdvanDevelop | 258 | 73 | 341 |
| UnderConstr | 211 | 56 | 267 |
| Operating | 338 | 187 | 525 |
| Tabled | 196 | 23 | 219 |
| Canceled | 180 | 33 | 213 |

## Conclusions

The addition of new power plants is much more prevalent in states that have either restructured their retail electricity markets or signaled an initial intent to do so than in states that have taken no restructuring actions. New power plant development is also more prevalent in areas of the country with a robust wholesale market infrastructure, such as exists in well established ISOs or RTOs. We also found a difference in the ownership of new power plants across states, with non-utility companies accounting for the bulk of new power plants in states taking restructuring actions, while utilities still have a strong or dominant role in new development in states that have not restructured at all. These patterns indicate that state regulatory actions are an important determinant of how well restructuring at the national level will ultimately work. The bulk of the potential benefits of restructuring the industry will come from improvements in efficiency of wholesale generation and sale of electricity and this depends critically on the ability of new companies to enter and exit. However, non-utility companies are far less likely to make the investments necessary to achieve these benefits in states that are not committed to developing a competitive environment. Finally, regulatory and market uncertainty create an environment in which developers invest in real options to build power plants, giving up or exercising their options over time as better information is revealed. The absence of a clearly defined federal restructuring policy and the inconsistency of regulatory approaches taken by states and provinces, therefore, increases total development costs and creates barriers to achieving the goal of competitively supplied electricity. The further exploration of the real options nature of power plant development is the subject of ongoing work by the authors.

## Footnotes

[1] A more complete description of the database and the steps followed to develop it can be found in Ludwigson et al (2003).

[2] Utilities in states that have not restructured their retail electricity markets also face captive demand and are typically still rate-regulated. These utilities typically get approval to build new projects and with that approval comes an almost certain guarantee that they will get a normal regulated rate of return on their investment, as their total approved costs are eventually passed on to consumers. This also partially explains the lower proportion of "false starts" in the utility owned projects.

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