Capacity Markets and Market Stability

The good news is that market stability can be achieved through a combination of longer-term contracts, auctions for far enough in the future to permit new entry, a capacity management system, and a demand curve. The bad news is that if and when stable capacity markets are designed, the markets may seem to be relatively close to where we started – with integrated resource planning. Market ideologues will find this anathema.

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I. Introduction

An important concept has been missing in the design of competitive electricity markets. This concept is the clear link between market stability (measured by capacity price volatility), the cost of capital, and the capacity price. Market stability (low capacity price volatility) is clearly good for consumers because it reduces the cost of capital and the capacity price. Market instability (high volatility) is clearly bad for consumers because it increases the cost of capital and the capacity price. Proper design of the capacity markets can achieve market stability.

This article explains why market stability reduces the cost of capital and the capacity price, then proceeds to a discussion of design options for achieving this desired stability.

II. Market Stability

The effect of market stability on customer prices can be explained with five sequential arguments:

 1040-6190/$–see front matter doi:/10.1016/j.tej.2006.02.001

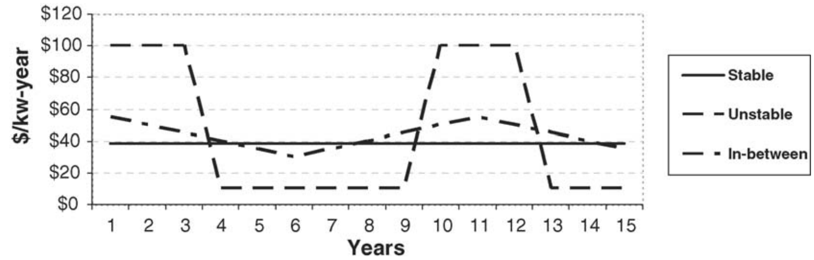

Figure 1: Project Cash Flows

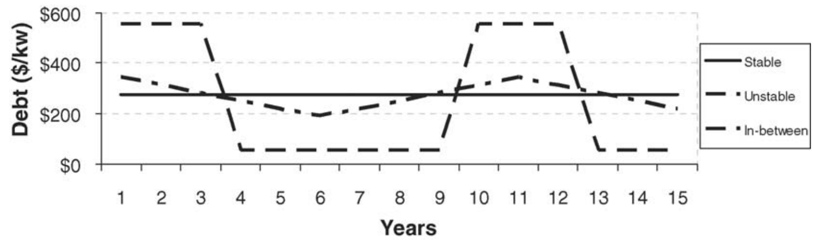

Figure 2: Debt Permitted by Credit Agencies and Lenders

1. The structure of the markets determines cash flow volatility;
2. Cash flow volatility determines the financial structure used to finance capacity additions;
3. The financial structure determines the cost of capital;
4. The cost of capital determines the capacity price; and
5. The capacity price affects customer costs.

Each argument is discussed in turn.

The structure of the markets determines cash flow volatility. In stable markets, cash flows are stable because capacity prices are stable. In unstable markets, the cash flows are volatile because prices are volatile, going from very high when markets are short of capacity to very low when the markets have surplus capacity. This is the typical boom-bust cycle of capital-intensive industries (**Figure 1**).

In this example, cash flows climb to above $75/kW-year in an unstable market when the markets are short of capacity, and then fall to nearly $0/kW-year when too much new capacity is added. The cash flows stay at this low level until the surplus capacity is absorbed by the market and a shortage reappears, starting the cycle over again.

In contrast, in a stable market, the cash flows remain at about $25/kW-year, since the boom-bust cycle is avoided. There are, of course, in-between markets where the booms and busts are moderated.

Market stability determines the financing structure used to finance capacity additions. The key concept here is that the amount of debt is limited by coverage ratios – cash flow divided by debt service (interest payments plus principal repayment) – at the minimum cash flow. The credit agencies and lenders will provide a higher percentage of debt for a project with a higher minimum cash flow, and a lower percentage when the minimum cash flow is lower. They will not lend based on maximum or average cash flow, since cash flows would not adequately cover the debt service when the cash flows are low (**Figure 2**).

In this example, the project could borrow nearly $400/kW in a stable market, but less than $100/kW in an unstable market. If the new capacity were a combustion turbine, the percent debt that could be borrowed would approach 90 percent in a stable market but would be below 20 percent in an unstable market.

The financial structure determines the cost of capital. While interest rates and returns on equity have a relatively modest effect on the cost of capital, the major driver of the weighted average cost of capital (WACC) is the percentage of debt (**Table 1**).[1]

In this example, the WACC in a stable market is 5.9 percent versus 17.2 percent in an unstable market. This is an enormous difference driven primarily by the percentage of debt in the capital structure. The interest rate is assumed to be the same in both markets, but the ROE is higher in the unstable market because the

Table 1: Weighted Average Cost of Capital

	Stable	Unstable
Capital Structure		
Debt (%)	87	18
Equity (%)	13	82
Cost		
Debt (%)	7.5	7.5
Equity (%)	15.0	20.0
Tax rate (%)	40	40
WACC (%)	5.9	17.2

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Table 2: Capacity Prices

	Market Structure	
	Stable	Unstable
WACC (%)	5.9	17.2
Real Capital Charge Rate (%)	6.1	20.1
Initial Capital Costs ($/kW)	400	400
Annual Capital Charges ($/kW-year)	24	80
FOM ($)	10	10
Energy Margin ($)	2	2
Capacity Price ($/kW-year)	32	88

The real capital charge rate is calculated to provide annual capital charges (constant in real terms) that will earn the WACC over the term of the investment. Annual capital charges are the real capital charge rate time the initial capital costs (e.g., 6.1% * $400/kW = $24/kW-year). The capacity price is the sum of annual capital charges plus FOM minus the Energy Margin (e.g., $24 +$10 −$2 +$32). The $88/kW-year represents the required *average* price over the life of the investment, not the peak price.

Table 3: Consumer Costs ($/kWh)

	Market Structure	
	Stable	Unstable
Energy Costs	45	45
Other Costs	15	15
Capacity Price (at 40% load factor)	9	25
Total Costs	69	85

For a consumer who uses 12,000 kWh/year, this is a difference represents nearly $200/year.

equity holders would be taking on additional risk.

The cost of capital determines capacity prices. When new generation capacity is needed, the capacity price will be the price required to induce investment in new generation capacity, often called the ''cost of entry.'' This price is the annual capital charges required to provide a return of and on invested capital (at the required WACC) plus fixed operations and maintenance (FOM) costs minus the expected energy margin (which is revenues from selling electric energy minus variable costs, which are primarily fuel). These calculations are illustrated in Table 2.

In this example, the required capacity price is $32/kW-year in a stable market and $88/kW-year in an unstable market. The difference is nearly a factor of three. The FOM and the energy margin are assumed to be the same. The entire difference is due to the different costs of capital, which drive the annual capital charges via the capital charge rate. The higher the cost of capital, the higher the capital charge rate, and vice versa.

Capacity prices affect customer costs. Since consumers must ultimately pay the capacity prices, higher capacity prices mean higher customer costs, and vice versa. Clearly, overall consumer costs would be lower with a capacity price of $32/kW-year than $88/kW-year.

If the rest of the consumer bill were $45/kWh for energy and $15/kWh for other costs, the total consumer costs would be $69/kWh in a stable market and $85/kWh in an unstable market (Table 3).

Also, market stability affects the kind of new capacity that will be built. The lower WACC in a stable market favors lower-energy-cost generation capacity which has higher initial capital costs. Conversely, the higher WACC of an unstable market favors

Table 4: Comparison of Full Costs of New Generation Capacity

	CT	Coal	CT	Coal
Capital				
Debt (%)	87	88	18	55
Equity (%)	13	12	82	45
Costs				
Debt (%)	7.5	7.5	7.5	7.5
Equity (%)	15.0	15.0	20.0	20.0
Tax Rate (%)	40.0	40.0	40.0	40.0
WACC (%)	5.9	5.8	17.2	11.5
Real Capital Charge (%)	6.1	6.0	20.1	12.2
Capital Costs ($)	400	1,500	400	1,500
Annual Capital ($)	24	90	80	183
FOM ($)	10	30	10	30
Energy Margin ($)	2	90	2	90
Capacity Price ($/kW-year)	32	30	88	123

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higher-energy-cost capacity which has lower initial capital costs (**Table 4**).[2]

In a stable market, a lower-energy-cost coal plant has a slightly lower capacity price ($30/kW-year) than a combustion turbine ($32/kW-year) and would likely be selected, often in order to diversify away from natural gas. In an unstable market, the capacity price of a coal plant ($123/kW-year) is much higher than of the combustion turbine ($88/kW-year) and would likely not be selected despite concerns about heavy reliance on natural gas. Hence, over time in a stable market both energy costs and capacity prices would be lower than in an unstable market.

III. How to Achieve Market Stability?

Given that capacity prices would be lower in a stable market and given that a stable market encourages new generation capacity with lower energy costs, how then can a stable market be achieved? Fortunately, policymakers (market designers) have some good options from which to choose, and they can mix and match.

One option is to return to regulation. This would provide much more stability than an unstable market, but it is not as stable as a stable market. Under regulation, the percent debt is typically about 50 percent. Under an extremely stable market (such as a long-term contract), the percent debt could exceed 80 percent.[3] Hence, the cost of capital can be much lower in an unregulated, stable market.

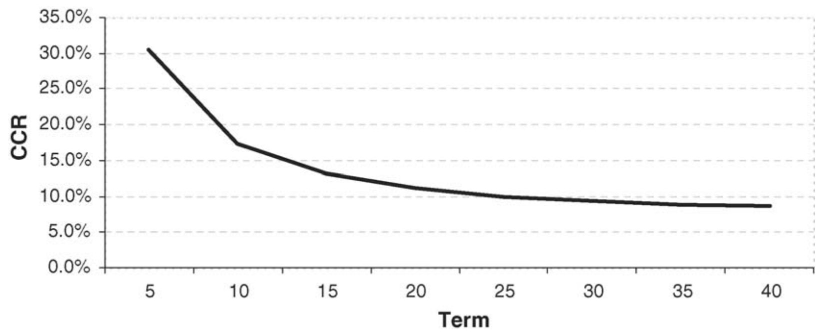

Figure 3: Effect of Contract Term on Capital Charge Rate

Another option is to extend the effective date of any capacity market auction far enough into the future that entry is a viable option. Short-term markets (this month, this year) can only allocate existing capacity. No new capacity can be added in time to serve a short-term market. If the auctions were held this year for capacity four to six years out, new entry would be viable. The market price of new entry would cap the capacity price. Otherwise, in a short-term market, the maximum capacity price is infinite in a shortage, so that market designers have felt obligated to impose an artificial cap on prices.

Another important option (which can be adopted concurrently with a future-year market) is to extend the term of the contract. On a long-term contract, the price is fixed over the term of the contract, providing maximum price stability. The longer the term of the contract, the longer the period over which the initial investment can be amortized. With a short-term contract, either the investment must be amortized over the short term or the market is deemed much less stable since the price that will be available at the end of the short-term contract is uncertain. **Figure 3** shows the effect of contract term on the capital charge rate, which has a direct affect on the capacity price, as discussed above.

So a shorter-term contract leads to a higher capital charge rate because the investment must be allocated over a shorter term and/or because the market is deemed to be less stable. Conversely, a longer-term contract solves both problems; it provides stability over the longer term of the contract.

Another option, with or without any of the above, is a capacity management system. Such a system would give the regional transmission organization (RTO) or the equivalent the power to procure new capacity directly when it was needed and to approve (or deny) applications to add new capacity. With these powers, the RTO (or the equivalent) could avoid large surpluses and large shortages, thus avoiding large swings in the capacity price, whatever the rest of the market design.

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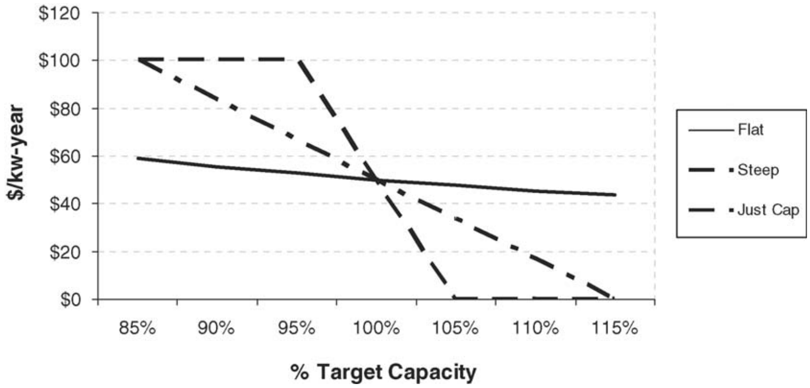

Figure 4: Alternative Demand Curve Designs

Another option is a ''demand curve,'' which can also be adopted concurrently with any combination of the above. A ''demand curve'' is designed to mitigate the boom/bust nature of capacity markets. With a demand curve, when there is a slight shortage, the price increases a little (but not a lot), and when there is a slight surplus, the price decreases a little (but not a lot) (see **Figure 4**).[4]

While the demand curve has positive attributes in concept (mitigating boom/bust cycles), there are difficult implementation problems. First, in a surplus market, the initiation of a demand curve typically means an increase in the capacity price (and consumer bills), as the price goes from very low to a higher level on the demand curve. Parties selling capacity like this. Parties buying capacity do not. A solution is to phase in the demand curve gradually, so that prices do not increase much until about the time that new capacity is needed.

A bigger problem is getting the level of the demand curve right. The level of the demand curve is set by the cost of entry because a defining point on a demand curve is the cost of entry at about 100 percent of target capacity. But the cost of entry is materially affected by the cost of capital and corresponding capital charge rate, and, as discussed above, the cost of capital is determined by the stability of the market.

The more stable the market, the lower the cost of capital, and vice versa. See Table 1, which represents a cost-of-entry calculation. In a stable market, the cost of entry would be $32/kW, but in an unstable market the cost of entry would be $88/kW. To get the level of the demand curve right, one must be able to discern whether to set the cost of entry at $32/kW or $88/kW or somewhere in between.

The ''right'' level for a demand curve depends on the ''market'' cost of capital, which depends on the volatility perceived by the market. This volatility depends on the other attributes of market design, including the year of the auction (how far into the future), the length of the contract, the capacity management system, and the shape of the demand curve. Understanding the volatility associated with any particular market design is a hard problem. Hence, it is very hard to get the level of a demand curve right.

Unfortunately, getting the level of the demand curve right has not yet received adequate attention. The effect of market stability on the market cost of capital has apparently been missing from the market design deliberations so far. Currently, the level of demand curves is set by an assumed capital structure (used in calculating the cost of entry) that approximates a regulated capital structures without apparent regard for the effect of market stability/instability on the capital structure.

If the market participants see less stability (more capacity price volatility), the ''market'' capital charge rate is likely to be higher than the capital charge rate used to calculate the cost of entry, and the level of the demand curves would be too low. Conversely, if the market participants see more stability, the level of the demand curves would be too high.

If the level is too low, the target level of capacity (providing a target reserve margin) would not be built. New capacity would enter when the capacity price provides the market WACC. This would be higher up the demand curve. This lower level of capacity would also lead to greater volatility in the energy markets.

If the level is too high, more capacity would be added than the target level.

IV. Good News and Bad News

The good news is that market stability can be achieved. Market designers can adopt some combination of longer-term contracts, auctions for far enough in the future to permit new entry, a capacity management system, and a demand curve.

Additional good news is that energy market designs, such as locational marginal prices, need not be affected by the capacity market designs. Energy markets can be designed as efficiently as possible, without regard to capacity market design.

The bad news is that if and when stable capacity markets are designed, the markets may seem to be relatively close to where we started – with integrated resource planning. Market ideologues will find this anathema. But others may give less weight to ideology and focus instead on consumer costs. Clearly, stable markets result in much lower capacity prices for consumers than unstable markets.

But there are other considerations as well. One risk to consumers that needs to be avoided in designing stable markets is avoiding cost-plus regulation and the "used and useful" concept. This combination led to enormous unnecessary costs, borne primarily by consumers in the 1970s and 1980s. Another risk to be avoided is creating a process that results in too much of the wrong kind of capacity being built. Unfortunately, the historical evidence on this one is mixed. Under regulation, consumers got stuck with too much nuclear and coal in the late 1970s and 1980s. Under free markets, consumers got stuck with too much gas capacity, in this decade. Under regulation, consumers had to pay (most of) the capital costs of the excess coal and nuclear capacity, but at least they got the advantage of low fuel costs. Under free markets, consumers were not stuck with the excess capital costs of too much gas capacity (since capacity prices plummeted to the detriment of equity investors and creditors), but consumers were stuck with too much expensive gas-fired generation that is keeping market energy prices very high.

The challenge for market designers is to capture the material advantages of market stability for consumers without subjecting consumers to potentially equivalent or even worse risks. The tools are available. All that is required is some careful creativity.■

Endnotes:

1. The WACC is calculated as the percent debt (%D) times the cost of debt (I) times one minus the tax rate ($1 - t$) plus the percent equity (%E) times the return on equity (ROE):

$$\text{WACC} = \%D{*}I{*}(1-t) + \%E{*}\text{ROE}.$$

2. A coal plant can carry more debt than a CT, particularly in an unstable market, because the energy margin of a coal plant is much higher, providing annual cash flows independent of the capacity price.

3. To get the full benefit of a longer-term contract, the buyer must be extremely creditworthy. If existing utilities sign too many of these contracts, the contractual obligations will be deemed debt by the credit agencies, so that the utilities would need to sell additional equity to restore the debt/equity balance on their balance sheets. Consumers would have to pay an ROE on this equity and hence not get the full benefit of new generation capacity that is highly leveraged. A solution to this problem is to let the buyer be the regional transmission organization rather than a load-serving entity. Individual loads can switch from one load serving entity to another, but they cannot switch RTOs.

4. Demand curves that are a part of existing and proposed market designs are somewhat more complex, but the concepts are the same. The steeper the curve, the more volatile prices will be. The flatter the curve, the less volatile they will be.

Market ideologues will find this anathema.