Appendix F. Estimation of Price Premium from New Jersey Data (Table 6-2)

Appendix F. Estimation of Price Premium from New Jersey (Table 6-2)

In New Jersey, there are two different full requirements products procured through competitive auctions.

- The BGS-FP product is for residential and small customers, who pay tariffed fixed c/kWh rates for electricity. The utilities solicit 3-year BGS contracts for full requirements service, once per year. Each year, enough 3-year contracts are procured to cover 1/3 of the utility's BGS-FP load at all times (in other words, one-third of the hourly BGS-FP load in every hour of a 3-year period). Therefore, for example, in the 2014-2015 delivery year, 1/3 of the supply comes from 3-year contracts solicited and executed earlier in 2014, 1/3 from 3-year contracts solicited and executed in 2013, and 1/3 from 3-year contracts solicited and executed in 2012.
- The BGS-CIEP product is for industrial and larger commercial customers. The rates paid vary with the price of energy in the PJM spot market. Each year the utilities solicit BGS-CIEP contracts for variably priced, full requirements service to cover 100% of the BGS-CIEP load in the delivery year beginning in June. BGS-CIEP suppliers are paid based on both capacity and energy. The price set in the BGS-CIEP auction is expressed in terms of $/MW-day. The MW metric refers to the PJM capacity requirement. The capacity requirement varies daily based on the number of customers taking BGS-CIEP service.[1] BGS-CIEP suppliers are also paid – essentially reimbursed – for their network transmission service costs, based on their allocated peak load, which varies daily in the same way as the PJM capacity requirement. Finally, the BGS-CIEP suppliers are paid for the energy they deliver at the PJM spot price (zonal LMP) plus $6/MWh, regardless of how the supplier actually procured the energy; the $6/MWh is a proxy for PJM ancillary service costs. Therefore the total payment to BGS-CIEP suppliers in month *m* is:

$$CIEP\_TOT\$_m = \sum_{d \in m} CIEP\_CAP_d \cdot CIEP\_PR\$_Y + \sum_{d \in m} CIEP\_PLAX_d \cdot XRATE\$_m + \sum_{h \in m} CIEP\_LD_h \cdot \left(PJM\_ZLMP\$_h + \$6/MWh \right)$$

  Where

  - d is a typical day in month m, h is a typical hour in month m
  - $CIEP\_TOT\$_m$ is the total CIEP payment in month m
  - $CIEP\_CAP_d$ is the Supplier Responsibility Share of the PJM capacity requirement for day d
  - $CIEP\_PR\$_Y$ is the CIEP contract price for year Y, in $/MW-day
  - $CIEP\_PLAX_d$ is the Peak Load Allocation for network transmission for day d
  - $XRATE\$_m$ is the tariffed transmission rate applicable in month m, in $/MW-day
  - $CIEP\_LD_h$ is the total CIEP load in hour h
  - $PJM\_ZLMP\$_h$ is the PJM zonal LMP in hour h.

The BGS-CIEP contract price covers risks associated with delivering electric energy to customers, except for variations in the cost of the energy itself or in the network transmission rate. The additional service provided by a BGS-FP supplier is price insurance, fixing the cost of energy. The total *expected* payment per MWh to BGS-CIEP suppliers is:

Expected PJM zonal LMP + $6/MWh + converted transmission rate + converted BGS-CIEP price

The term "converted", as applied to the tariffed transmission rate and the BGS-CIEP contract price, means in each case the conversion from a $/MW-day basis to a $/MWh basis. If the utility were to serve BGS-FP load from the BGS-CIEP supply, then that is the price it would pay, provided that the expected zonal LMP and the

[1] Conceptually, each customer is "tagged" with an individualized capacity requirement, and the BGS-CIEP daily capacity requirement is the sum of the requirements of all customers taking BGS-CIEP service that day.

conversions to \$/MWh were computed based on expected hourly BGS-FP loads. That is a significant consideration, since BGS-FP and BGS-CIEP load profiles and load factors should differ.

On the other hand, the amount paid per MWh by the utility to BGS-FP suppliers (the supply cost) is simply the BGS-FP contract price. Because the BGS-FP supply is bought equally from three procurements, the utility's average payment per MWh for BGS-FP supply is the average of the prices in the last three procurements. For example, the retail BGS-FP supply cost for 2013-4 was the average of the prices from the BGS-FP procurements conducted in 2011, 2012, and 2013. The additional service provided for the BGS-FP price, over and above the service provided for the BGS-CIEP price, is price insurance, that is, the service of providing supply for a non-varying supply cost. The difference between those two prices must be the premium paid for price insurance:

Premium = BGS-FP supply cost

– Expected PJM zonal LMP – \$6/MWh – converted transmission rate – converted BGS-CIEP price

That is the equation used to compute the values in Table 6-2. It is applied to a 3-year contract; the BGS-CIEP contract price is therefore an average price over the three years, as is the transmission rate. The computation of the zonal LMP and the conversions to \$/MWh rely heavily on data obtained from the "BGS Data Room".[2] The specific data used were the hourly BGS –FP loads by utility in MWh, and daily BGS-FP peak load allocations in MW-day.

Treatment of load and Peak Load Allocation (PLA) data

When dealing with hourly loads and peak load allocations to convert the BGS-CIEP price to \$/MWh the following must be kept in mind:

- The PJM peak load represents the maximum load on the PJM system in the course of a year. It is approximately, but not exactly, the maximum hourly load.
- Each PJM customer or customer group is assigned or allocated its own "peak load". Larger customers with interval meters are assigned a peak load which represents their usage at the point in time coincident with the system peak. The remainder of PJM's peak load is *allocated* to other customer groups. The BGS-FP customer group's daily PLA is not necessary related to any day's maximum hourly BGS-FP load.
- There are actually two different peak load allocations, one for computing capacity requirements and one for computing transmission charges. They are different because the capacity requirement and transmission tariff are based on different definitions of peak load. They can be referred to as PLA (Capacity) and PLA (Transmission).
- The total PJM capacity requirement is equal to its peak load, plus a planning reserve margin. The planning reserve margin is around 16%; in the latest base residual capacity auction it was 15.8%. The IPA has used 16% as a generic approximation, and used 116% of the BGS-FP PLA (Capacity) to represent the daily PJM capacity requirement.
- Historical BGS-FP data can represent a different number of customers each day. Variations in the set of customers are captured in the daily PLA. Therefore the appropriate metric of hourly load, for any application dependent on load profiles rather than absolute load values, is the "normalized" load in MWh/MW-day.
- If the BGS-FP load in hour h is denoted FP_LD_h, and the BGS-FP PLA (Capacity) for day d (which includes hour h) is FP_PLAC_d, then the normalized BGS-FP load in MWH/MW-day is

$$FP\_LDN_h = FP\_LD_h / FP\_PLAC_d$$

[2] The data room is accessible at http://www.bgs-auction.com/bgs.dataroom.asp. It consists of data that has been provided to potential BGS suppliers in order to assist them in computing their price bids.

- The relationship between PLA (Capacity) and PLA (Transmission) changes annually. This means that PLA (Transmission) should also be measured in a "normalized" fashion, as a ratio. If the BGS-FP PLA (Transmission) for day *d* is denoted FP_PLAX_d, then the normalized BGS-FP load PLA (Transmission) for day *d* is the dimensionless ratio

$$FP\_PLAXN_d = FP\_PLAX_d / FP\_PLAC_d$$

Expected PJM Zonal LMP

The expected PJM zonal LMP depends on an effective date: considering an expected price to be the forecast of the price, one must specify the date on which the forecast was made. Three-year BGS-FP full requirements supply contracts are procured in a "descending clock auction" in February. NYMEX futures prices are market indicators of the price expectation and therefore a 36 monthly NYMEX on- and off-peak futures prices for the Tuesday following the first Sunday of February (i.e., the first Tuesday after February 2) was used.[3]

Each futures price was adjusted by a load shape multiplier, which represents the ratio of the load-weighted spot price to the average spot price. Load-weighting was based on BGS-FP load in MWh/MW-day, and the averaging was done over hours from January 1, 2005 through December 31, 2009. The expected spot price is a weighted average of the adjusted futures prices for each month and subperiod, weighted by the fraction of total BGS-FP load (in MWh/MW-day) in each, based on the average from the same period.

Converted BGS-CIEP price

The BGS-CIEP price was converted using the BGS-FP load profile but correcting for changes in the size of the BGS-FP customer base. The correction was done by assuming a constant PLA (Capacity) – that is, by using normalized loads. The computation averages the BGS-CIEP prices for three delivery years (Y1, Y2, and Y3) to compute a total BGS_CIEP payment. The conversion uses the average daily value of the normalized load over a four-year historical period *P* (the four delivery years preceding the period for which a contract is solicited):

$$CIEP\_PR\_MWh\$ = \frac{(CIEP\_PR\$_{Y1} + CIEP\_PR\$_{Y2} + CIEP\_PR\$_{Y3})/3}{\sum_{h \in P} FP\_LDN_h / 1461}$$

The BGS-CIEP auction for the first year occurred at the same time as the BGS-FP auction, and the auctions for the other two years occurred respectively one and two years later. Therefore, the BGS-FP premium should be estimated using suppliers' expectations of the BGS-CIEP prices. It was assumed that those expectations are unbiased forecasts. The BGS-CIEP price is primarily determined by the cost of capacity. At the time of the BGS-FP auction, the PJM RPM Base Residual Auction (BRA) for the first two years covered by the BGS-FP contract that had already been held. Capacity pricing for the third year would still be uncertain. This means there should not be a great deal of uncertainty around the suppliers' expectations of the converted BGS-CIEP price *CIEP_PR_MWh$*.

Converted transmission rates

Transmission rates were converted by assuming a constant PLA (Capacity) – that is, by using normalized PLA (Transmission). The transmission rate varies over calendar years, rather than delivery years; it is presented here as if it varied monthly. Instead of a simple average the transmission rates must be averaged based on the normalized PLA (Transmission):

[3] Historical NYMEX futures prices were obtained from SNL.com.

$$XRATE\_MWh\$ = \frac{\sum_{m \in Y1 \cup Y2 \cup Y3} \left(\sum_{d \in m} FP\_PLAXN_d \cdot XRATE\$_m \right) \Big/ 1096}{\sum_{h \in P} FP\_LDN_h \Big/ 1461}$$

The 1096 in the formula represents three years including one leap day. Each of the three contract periods considered in the text contains a leap day.

At the time of the BGS-FP auction, the transmission rate is only known for the first seven months of the contract. So, the calculated premium and the auctions for the other two years occur respectively one and two years later. Therefore, the BGS-FP premium should also be estimated using the supplier's expectations of the transmission rates. It has been assumed that those expectations are unbiased forecasts.