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4 November 2022

The Secretary
Hon'ble Central Electricity Regulatory Commission
3rd & 4th Floor
Chanderlok Building
36, Janpath
New Delhi -110 001

Sir,

Comments on the Central Electricity Regulatory Commission

Staff Paper on "Power Market Pricing"

With reference to Public Notice No. Eco-4/2022-CERC dated 12 October 2022, we hereby submit our suggestions / comments in the Attachment on the Staff Paper on "Power Market Pricing".

Assuring you of our best attention.

Yours faithfully,

Executive Director
(Regulatory Affairs & Corporate Services)

Encl.

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Points for Discussion as outlined in CERC Staff Paper on "Power Market Pricing"

1. Does Pricing Methodology need a change?

1.1. As inferred on comparison of the two pricing methodologies, in a competitive market, any difference in cost, due to the two methodologies, becomes a function of the bidding behavior of the sellers.

1.2. It is imperative to mitigate the concern of super normal profits which may apparently be achieved through pay-as-bid auction. While participating in the market, generators quote price to receive their marginal costs and in addition, recover part of their fixed cost. Pay-as-bid auction may encourage sellers to offer high bid price (higher than marginal cost) to earn a profit and also recover fixed costs (business rationale).

1.3. Given these facts, would it make sense to switch to pay-as-bid pricing methodology and would it address the concerns regarding super normal profits for inframarginal generators under Uniform Market Clearing Price?

Summary of Response:

Since there exists empirical evidence that pay-as-bid auctions have seen lower prices being discovered, some regulators have found merit in shifting to pay-as-bid auctions. However, it has been highlighted that there is no proof that shifting to pay-as-bid auction mechanism increases welfare when compared to uniform market clearing auctions. Also, moving to pay-as-bid mechanism may change seller's bidding behaviour, and we might see higher market clearing prices as well – because demand bids are driven by desperation to fulfil the universal supply obligation. It is also submitted that policy changes in response to short-term shock may signal regulatory uncertainty and might dis-incentivise further investment in this sector.

Discussion:

1. Today in India high prices in exchange are driven by the buyer's desperation to meet their service obligations rather than seller's intentions to cover costs. This is apparent from the Order of the CERC 5/SM/2022 dated 6 May 2022, which cited behaviour of some buyers as the main cause to such high prices on the exchange [*Page 1, Annexure 1*]. It is hence clear that market clearing price is determined by buyer side desperation rather than supply side cost recovery. Suppliers might change their bidding behaviour identifying the seller's desperation, and we might see higher prices being discovered on the exchange.

2. It is also submitted that the period in question is experiencing a lot of concerns on excess revenues generated by inframarginal generators because of the high prices being

discovered. This period saw a number of one-off factors come into play – including a sudden spurt of economic activity after the Covid pandemic. Making policy changes based on transient situations and one-off shocks may be viewed as regulatory uncertainty and may lead to a higher perception of regulatory risks among investors. This might be detrimental to long term capacity addition in this sector as it may deter investments in this sector. It is thus submitted that policy changes like this may be made only after there is evidence of such concern of high amounts of excess revenues being realized by the generator even in periods of stability.

2. What should be the criteria for Regulatory Interventions?

2.1. Market power is what should be a matter of concern. That is, as a matter of principle, is intervention in the market is justified when the price spike is a result of market power or misuse of market position by suppliers.

2.2. One school of thought would argue that if the price rise is caused by demand behaviour, we need to correct demand side and not further scuttle supply side. Options include demand reduction (by demand reduction we don't mean load shedding) through pre-notified demand response programme. Studies prove that compensating demand for load reduction is more cost and operation effective than procuring peak power. The signals that occasional price spikes give - in terms of the need for proper load forecasting, reserve margin, resource adequacy, demand response and other fast response reserves like ESS, should not be lost sight of.

2.3. However, the other school of thought believes that India cannot afford very high price caps or the standard scarcity pricing framework.

2.4. Given these realities,

- Would it be advisable to define a tolerance level (for instance, how many times during a day or over the week/month are we tolerant with the price touching the ceiling) beyond which intervention is justified?
- What should be the basis for such intervention and tolerance level in the Indian context?
- Would it be advisable to define a dynamic price cap - for example, if the prices breach the tolerance level as defined above,
    - the price cap is automatically reduced to a point where say 90% or 95% of the supply is cleared? Or
    - generators are mandated to run and are compensated under administered route or based on some pre-specificed norms, till the situation (breaching the tolerance level) normalizes?

- Can a cap be considered on the excess revenues made by power plants that do not use gas or other high cost fuel to produce electricity, such as solar, wind, domestic coal, nuclear, hydropower and lignite? The cap could be uniform and set in advance based on the marginal generator amongst these inframarginal generators and all revenues that exceed the said cap may be collected by system operator.
- To partially capture the surplus profits made by the inframarginal generators, would it be advisable to impose a levy on supernormal profits, as was done by the Government for Petroleum?
- If price cap for inframarginal generators is levied, should the other supramarginal generators like gas based generating stations be left without a cap or a separate price of Rs 20 or so be levied for this segment as well?
- Any other suggestion?

Summary of Response:

Under the uniform market clearing price system, It is not advisable to implement revenue caps or to impose a levy on supernormal profits, because an ever-changing regulatory regime in response to short-term shocks might deter investments into this sector. It is also submitted that in case some of this excess revenue from the power sector is taxed, infusion of that surplus back to the consumers in the power sector in entirety is a matter of uncertainty. Imposition of a price cap is advisable to help manage the price burden of consumers, but significant study is needed to identify a threshold for tolerance as discussed.

Discussion:

1. In several States, profits from the export of electricity by discoms with embedded generating stations are shared with the consumers by mechanisms of gain sharing. In case of capping of any excess revenues realized by discoms who are also exporters of electricity, such gain share with consumers will also be reduced. Without such benefit of gain sharing, consumers will have to let go of tariff relief that such export provides. **Hence the idea of capping revenues or imposing additional levies should be considered in the light of lost benefit to consumers as well.**

2. If such revenue capping or taxation is introduced in uniform price clearing mechanism, excess revenues that were earlier recognized as return on investment for generators **will flow to the Government.** Considering the economic condition of the power sector in India, and the purchasing power of a large section of consumers is a concern, it is essential that this revenue flows back into the power sector, incentivising investments

in this sector to improve access to electricity to the consumers. Imposing any taxes opens up room for such revenue to flow outside the sector.

3. It may also be argued that such levy or caps will deter efficient capacity addition. With a growing need to drive investment in this sector, there is a need to allow some firms to make profits at levels their business plans demand. Imposition of arbitrary levies and caps result in drastic re-evaluations of business cases for generators and may result in stalled projects and withdrawal of investor interest.

4. It is also submitted that the proposals of capping revenues for generators has come up simply because of higher prices discovered on the exchange in the aftermath of the Covid crisis that had crippled economic activity to a large extent for the past couple of years in India. However, significant policy changes in response to transient situations or arbitrary shocks may not be in the best interests of the long term development of the industry. The period that saw high prices and triggered these concerns was a period of sudden spurt in economic activity, resulting in commodity shortages and limited accuracy in forecasting, a condition that may not be seen once economic activity stabilizes.

3. How do we address the negative impact of price cap?

3.1. While imposition of price cap ensures that the market prices remain reasonable and within bounds, the generators with variable cost higher than the price cap tend to go out of market. In order to attract more supply volume different countries have proposed measures of segmenting the market. While in Europe a price cap for only inframarginal technologies has been suggested, in India a proposal for introducing a separate High Price Market Segment within the existing day ahead market has been floated.

3.2. The following issues emerge in this context:

- What should be the basis for defining supramarginal or high cost generators? Technology or fuel source?
- Would there be enough liquidity in this small segment for collective transactions (demand and supply curve intersection) to take place?
- Would it lead to market power by these small sets of generators?
- If the high cost/marginal generator setting the market clearing price is a concern and a cause for market intervention, would Term Ahead Market (TAM) be a better option for such transactions to take place without affecting the rest of the buyers?
- Any other suggestion on mitigating the negative impact of price cap?

Summary of Response:

We believe that the section of 'High Priced Market Segment' has too many variables for any active regulatory interventions to have the desired effect.

Discussion:

Defining a 'High Price Market Segment' may not be complete with either technology or fuel source. For instance, an embedded generating station may be operating one day with a 30% load to cater to own consumers, and on another day with a 60% load. On the day it is running on the 30% load scenario, it may be willing to quote a sellers bid equal to, or lower than its variable cost of generation, as it can become essential to generate that additional 10%-20% operational load to ensure running of the plant, making it an inframarginal generator. On another day, it may not have such desperation and may quote a price that recovers part of fixed costs as well over and above variable costs. On such days, it may not quote a price below the market clearing price.

It is respectfully submitted that estimation of volume of such a segment will be extremely difficult under the mechanism of auctions, as estimating actual costs from auction data is very difficult. Considering the large degree of uncertainty in definition and numbers, we believe it should be left to the firms to operate in TAM Market or otherwise as such generators see fit, and active regulation may not be needed in this regard.

4. What should be the market design for incentivising demand response and energy storage system (ESS)?

4.1. Record-breaking temperatures (summer/winter) and increased level of economic activities after lifting of pandemic restrictions have pushed up the energy demand across globe, putting pressure on energy prices. A reduction in demand may ease this pressure on prices.

4.2. In EU, a region wide plan to introduce power savings is proposed which includes

- a mandatory 5% target during peak hours, when gas plays a bigger role in price-setting, and
- a voluntary 10% reduction in overall electricity demand

4.3. As witnessed, prices were driven high due to high demand coupled with low supply, Demand-side response in such crisis situations would help lower prices.

4.4. Given these realities,

i. What should the appropriate market structure/design to encourage flexible resources like Demand Response and ESS?

ii. Apart from Time-of-Day (ToD) tariff or dynamic tariff for varied consumer categories, what are the mechanisms that can be considered for encouraging such resources? Can we think of bringing aggregators to pool together such resources and participate in the market? If yes, what should be bidding criteria or the cost recovery mechanism for such resources given that their usage is going to be limited to a very small duration during the year?

Summary of Response:

It is unclear what the lines of revenue for ESS will be, but it is clear that ESS will greatly help power markets through temporal arbitrage. To help grow this industry, it is essential that some incentives are allowed to certain sections of players in the power landscape to procure ESS resources. We feel that ESS has its use case among distribution licensees who might be able to use decentralized ESS to manage peak load at substations. However, it may not be prudent to further incentivise aggregation in this industry, as the generators may feel hard done by the collusive practises in the market that are expected to follow such aggregation among ESS firms.

Discussion:

1. It is without a doubt that ESS are high investment projects, which will be essential going forward for energy security of the nation. At the initial stages, investments should be incentivised. As this is a previously untested technology from the perspective of the power sector, the business case of such firms are not clear. Lines of revenue are also unclear at the moment. Moreover, depending on location of such facilities, the usage patters of such firms will vary considerably.

2. It is expected having ESS will reduce the prices on the exchange, by making cheaper power available during periods of high demand. However, as it has been pointed out, this use case may be limited in terms of period of operation and revenue-generation. ESS may also find an use case in distribution networks in substations. ESS units may be strategically placed to store energy during periods of low demand, and during periods of peak demand, the ESS may be used to distribute this stored energy. This will reduce the need for high investment upgradations to the distribution network which are burdened during times of peak load. These considerations are articulated in the article by Jenkins and Weiss (2005) [*Page 6, Annexure 2*] Such investments by distribution licensees may be incentivised by capital subsidies. The nature and extent of such capital subsidies may be discussed by Hon'ble CERC as deemed fit through public consultation of this nature. It is important to recognize that this should be evaluated not simply as a cost-benefit analysis, but also to encourage the development of ESS technology within the country.

3. Incentivising aggregation in this industry may not be necessary if these firms have the proper tools and transparency to build a business case and ensure governance to realize expected cash flows. Incentivising aggregation might also be viewed as collusive practice in the exchange and may draw flak from standalone generators who rely on the exchange for revenues.

CENTRAL ELECTRICITY REGULATORY COMMISSION
NEW DELHI

Petition No. 5/SM/2022

Coram:
Shri P. K. Pujari, Chairperson
Shri I. S. Jha, Member
Shri Arun Goyal, Member
Shri P. K. Singh, Member

Date of Order: 6th May, 2022

IN THE MATTER OF:

Directions by the Commission to the Power Exchanges registered under the Power Market Regulations, 2021.

ORDER

The Commission vide order dated 1st April 2022 in Petition No. 4/SM/2022 (Suo-Motu) had in exercise of powers under Regulation 51 (1) of the Power Market Regulations 2021 (PMR 2021) directed the Power Exchanges until further orders, to re-design, with immediate effect, the bidding software in such a way that members can submit their bids in the price range of Rs.0/kWh to Rs.12/kWh for Day Ahead Market (DAM) and Real Time Market (RTM). One of the key grounds for the intervention by the Commission was the fact that 99% of the supply bids (for the period for which data had been analysed) were in the range of Rs.12/kWh and only 1% of the supply bids were higher than Rs.12/kWh. The objective was to protect the large number of buyers (consumers) from being compelled to bid a high price of Rs.20/kWh because of the bid behavior of a very few buyers.

2. The Commission has been regularly monitoring the volume and prices of electricity transacted in various contracts at the Power Exchanges. The following facts have emerged from the recent behavior in volume and prices at the Power Exchanges, based on the daily trade information published by the exchanges:

(i) The buy bid in DAM registered an increase of about 28% in the month of April 2022 as compared to March 2022, while that in RTM increased by 144% during the same period.

(ii) However, the cleared volume in DAM registered a decrease of about 30% in the month of April 2022 as compared to March 2022, while that in RTM decreased by 16% during the same period.

(iii) The volume traded in Term Ahead Market (TAM), Intra-day and Day Ahead Contingency (DAC) in the month of April 2022 witnessed an increase of about 120% over the volume traded in the month of March 2022.

(iv) Of the total volume traded in TAM, Intra-day and DAC contracts around 37.31% was traded at price in excess of Rs.12/kWh in April 2022, i.e., above the ceiling price of Rs.12/kWh in the DAM and RTM market segments.

(v) Apart from the generators, the distribution companies (Discoms) are also selling in DAM/RTM and in TAM/Intra-day/DAC.

3. As a result of setting the ceiling price at Rs.12/kWh for DAM and RTM, the Market Clearing Price (MCP) in DAM and RTM has been frequently hitting the ceiling price at Rs.12/kWh with the volume of buy bids much more than the volume of sell bids. As a result, the cleared volume is getting pro-rated amongst the buyers quoting the ceiling price in proportion to their bid volumes. Thus, even if buyers are willing to pay the ceiling price, they are not getting the full bid volume. Due to apprehensions of such pro-rating, it has been observed that buyers have increased their bid volumes at the ceiling price substantially, but are still not able to meet their demand of electricity in the collective transaction segment of Power Exchanges, viz., DAM and RTM. Therefore, to fulfill their supply obligations, the buyers are shifting to other market segments of Power Exchanges, such as TAM.

4. It has also been observed that the difference in ceiling price between DAM/RTM and TAM has led to shift in supply volume from DAM/RTM to TAM. Representations have been received from some States highlighting that this is affecting their prospects of getting power from DAM/RTM segments of the Power Exchanges and they have to go to TAM segment for meeting their demand. Some Discoms have also represented that the differential pricing between DAM/RTM and TAM/Intra-day/DAC market segments is influencing the behavior of the sellers and have expressed concerns about the likely profiteering by sellers on account of the price differential in the two market segments in the Power Exchanges.

5. In this context, it is pertinent to note that the TAM/Intra-day/DAC market is bilateral in nature and the buyers and the sellers are matched on one to one basis, unlike in case of

collective transactions. In other words, the buyers and the sellers voluntarily agree to a price which does not affect any third party. The buyers enter into such transactions with their eyes and ears open and with full knowledge of the consequences. Under these circumstances, the role of the buying Discoms and the SERCs regulating the Discoms assumes significance. If there are concerns about high prices at which Discoms are entering into bilateral transactions, it is the responsibility of the concerned SERCs to direct the buying Discoms not to enter into such transactions beyond the threshold price and volume limit that the SERCs consider appropriate.

6. The counter-argument could be that the buyer's behavior at present is scarcity driven. But the question is whether by imposing a ceiling price in different segments of the Power Exchange market adequacy of supply in this trading platform can be guaranteed. The sellers might then explore some other avenues of sale which might not be subjected to direct regulation.

7. There is also a need to recognize that the buyers also include open access consumers and bulk consumers, who may be willing to buy power at a higher price which still makes economic and financial sense to them. Under the regime of ceiling price in different segments of the Power Exchange, such consumers are also effectively denied access to their full requirement of power.

8. West Bengal State Electricity Distribution Company Limited (WBSEDCL) in its letter dated 22.04.2022 has alleged that the sellers are circumventing the Commission's Order dated 01.04.2022 by entering into negotiations and then conducting their transaction under TAM contracts. This is being done with a view to bypass regulatory measures put in place by this Commission. While the Commission is having this aspect investigated, we also note that some of the Discoms and other licensees in States were also engaged in selling power in TAM/Intra-day/DAC post the ceiling price of Rs.12/kWh for DAM and RTM. The Commission also expects that if Discoms or any other licensees are party to such transactions, the concerned SERC also takes appropriate action against such Discoms or licensees.

9. The Ministry of Power vide letter dated 29.04.2022 has issued directions to the Commission to issue orders for capping the market price at Rs.12/kWh or less for all segments of Power Exchanges (regulated by CERC), including Term Ahead Market (TAM).

10. The Commission is engaged in detailed analysis of the behavior of the market participants in different segments of the Power Exchange. However, taking cognizance of the increasing trend of prices driven by shortage of supply and sudden increase in demand, and in view of the alleged profiteering by the sellers which also includes Discoms, the Commission finds it expedient to intervene in the market in public interest on following grounds:

a) need for a uniform price ceiling in all segments of the Power Exchanges so that there is no shift in supply volume from one segment of the Power Exchanges to another segment, induced by differential ceiling price between different market segments of the Power Exchanges; and
b) there is no profiteering by the sellers in the backdrop of increased demand and reduced supply.

11. The Commission analysed the data available on MERIT website (www.meritindia.in) maintained by the Ministry of Power and noticed the following trend during the period from 05.04.2022 to 30.04.2022:

a) Given the present constraints of gas supply, additional generation in the present situation of shortage is likely to come mostly from the coal based, including imported coal based generating stations. Accordingly, the marginal cost of generation from the coal based generating stations has been considered for price trend analysis.
b) Of the coal based generating stations, the marginal generators are based on imported coal. As per the All India MERIT Summary, the energy charges of the marginal generators ranged from Rs.7.30/kWh to Rs.8.82/kWh for the period under analysis.

12. The above analysis reveals the energy charge of the marginal generator to be in the range of ~Rs.9/kWh. In addition, if the expectation of recovery of part of the fixed cost and transmission charge are factored in, the ceiling price of Rs.12/kWh seems reasonable.

13. Regulation 51 of the Power Market Regulations 2021 (PMR 2021) provides as under:

*"51. **Other circumstances requiring intervention***
(1)The Commission may, on being satisfied that a situation of abnormal increase or decrease in prices or volume of electricity in the Power Exchange exist or is likely to

occur in the market, by an order, give such directions as may be considered necessary. …….”

14. In exercise of the aforesaid powers under Regulation 51(1) of the PMR 2021 and in view of the analysis of price trends in the preceding paras and in order to balance the interests of investors in terms of reasonable return and protecting consumer interests, the Commission hereby directs the Power Exchanges, from the date of this Order till 30th June 2022, to re-design, with immediate effect, their software in such a way that members can quote price in the range of Rs.0/kWh to Rs.12/kWh in DAM (including GDAM), RTM, Intra-day, Day Ahead Contingency and Term-Ahead (including GTAM) Contracts. The contracts which have already been transacted till the date of issuance of this Order shall be delivered and settled as per the earlier terms and conditions. Application of the price ceiling for a limited period is based on the belief of the Commission that intervention in the market should not be prolonged unless absolutely necessary in public interest as in the existing circumstances prevailing in the country.

15. The Exchanges are further directed to submit the compliance of this direction within two days from the date of this Order. With coming into effect of this Order, the Order dated 01.04.2022 in Petition No. 4/SM/2022 shall stand superseded.

16. The Petition No. 5/SM/2022 is disposed of in terms of the above.

Sd/-	**Sd/-**	**Sd/-**	**Sd/-**
(P.K. Singh)	**(Arun Goyal)**	**(I.S. Jha)**	**(P.K. Pujari)**
Member	**Member**	**Member**	**Chairperson**

Annexure 2

Estimating the Value of Electricity Storage: Some Size, Location, and Market Structure Issues

Thomas Jenkin (National Renewable Energy Laboratory, Washington, D.C., USA); Thomas_Jenkin@nrel.gov
Jurgen Weiss (LECG)

Introduction
The purpose of this paper is to better understand some of the potential benefits of electricity storage, particularly those associated with competitive wholesale power markets such as PJM.[1] Electricity storage devices have the potential to provide significant benefits through reduced energy costs to end users; improved utilization of the existing generation, transmission and distributions assets; as well as associated benefits from deferred capital improvements and/or additions. Additional benefits stem from its potential to firm up the output of intermittent resources, by providing a partial hedge and dampening effect against high natural gas prices and increased price volatility and by rendering the exercise of supplier market power more difficult. Many of these factors also contribute more generally to improved security and reliability, including risk mitigation against market disruptions.[2] These potential benefits must be weighed against the costs of such storage devices. We discuss some of the implications of ownership structure and market rules on the ability to appropriate the benefits associated with storage devices, and to what extent that makes construction of storage devices feasible if societal benefits exceed societal costs. Increasing the total amount of storage in a given electricity system can lead to substantial shifts in the size and nature of benefits between the various stakeholders – and these need to be considered from both the short-term and longer-term perspective.

In this paper, we give particular emphasis to the impact on the economic value of electricity storage due to: (i) the significant increases in the price of natural gas over the past few years – and the related issue of how location more generally affects arbitrage value, (ii) the impact of changes in the total amount of storage in a given electricity system, and (iii) the effect of ownership structure/market structure and rules on the division of benefits. These three factors are important to any real investment decision (e.g., whether to build, where to build, how much to build).

This paper is intended to contribute to defining a framework for such analysis and provide some preliminary results and insights.[3]

Arbitrage Value of Small-scale Storage and the Impact of Rising Natural Gas Prices and Locational Considerations
A storage device captures arbitrage value by using cheaper off-peak power and then selling higher-priced power during peak hours. A number of earlier studies have looked at the arbitrage value of small electricity storage devices in the United States. Despite recent increases in the arbitrage value of electricity storage, these studies have generally found that arbitrage alone is not sufficient to justify building such a device.[4]

A number of methods can be used to bound the economic arbitrage value of storage. Simple operational rules provide a lower bound, while (monthly) price duration curves – where the highest hourly prices are mapped to the lowest priced ($1/\eta$) hours – provide an upper bound. For PJM, in 2002, these techniques bounded the value

[1] This paper is based on a presentation for the EESAT 2005 conference in San Francisco on October 17, 2005.
[2] Ancillary services are another source of value (though usually as alternatives rather than additions to arbitrage). These can be particularly attractive because they value capacity over energy, at least for limited amounts of storage (also see Footnote 3).
[3] Subject to funding considerations, it is hoped to expand this preliminary work into a larger study that will examine the value of various benefits at a more local level within a specific region, as well as more generally across a number of regions.
[4] Devices are often considered to be so small, in that their operation does not collapse or substantially affect the peak-off-peak prices. See e.g., Frank Graves, Thomas Jenkin, and Dean Murphy, *Capturing the value of storage in the energy and reserve markets*, Electrical Energy Storage – Applications and Technologies conference in Orlando, Florida, September 18, 2000 (EESAT 2000).

of a typical storage device at $50 to $75/kW-yr.[5] Peak/off-peak price differences and price volatility are key drivers in determining the value of arbitrage. Other factors include the efficiency of the device, how it is operated – including degree of "perfect foresight" – and device size constraints.

Between 2002 and 2004, the price of natural gas has risen sharply from typically around $2/MMBtu to $4/MMBtu in 2002 (at Henry Hub) to an average of more than $5/MMBtu in 2003 and in 2004.[6] Because the value of storage is driven by the difference between peak and off-peak prices – which, in turn, will reflect both the fuel mix in the region and the underlying fuel prices – the increase in the potential arbitrage value of storage in PJM in 2003, while significant, was not nearly as high as the relative increase in natural gas prices (though the upper bound reached $100/kW-yr, or more for an unconstrained device.)[7] To understand this, it is useful to consider the different impact of a $2/MMBtu increase in price for a gas generator, a storage device, and renewable energy (wind or solar) (see Figure 1).[8]

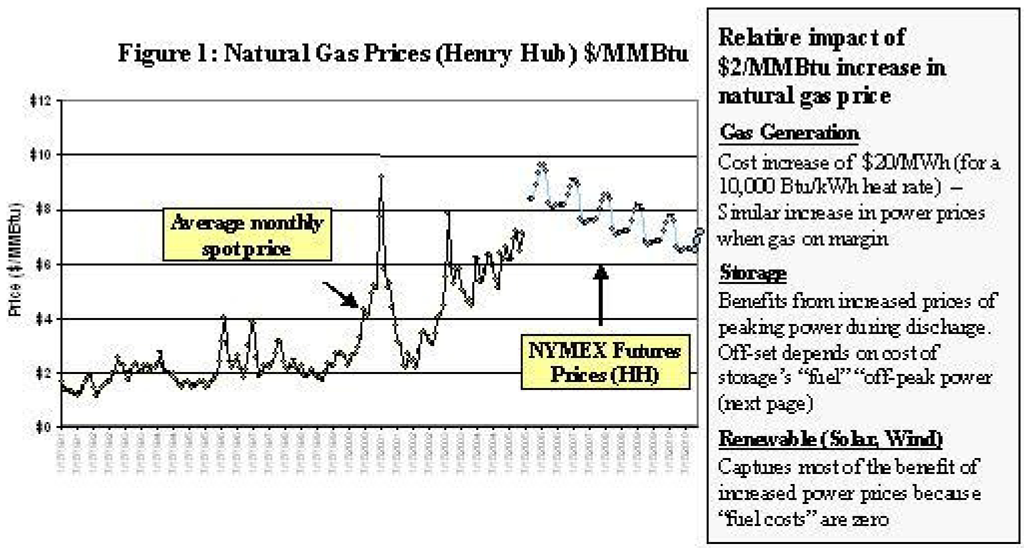


Figure 1: Natural Gas Prices (Henry Hub) $/MMBtu

Higher gas prices push power prices up at peak times when – as is common – gas is on the margin. However, conventional gas-fired generation on the margin does not profit more under such scenarios because it is still on the margin, i.e., the cost of fuel has increased. By contrast, a storage device's fuel is "off-peak" power. This will be much less affected by the price of gas – though how much less depends on the off-peak fuel mix. If the off-peak charging hours are driven by nuclear or hydro, storage will receive the complete benefit from the rise in gas prices. Even if gas is on the margin for some of the off-peak hours, rising gas prices will increase the

[5] Optimization techniques that allow for physical device constraints and have perfect foresight will fall between these boundaries, but also tend to be overoptimistic. Efficiency, η of 80% was used for arbitrage estimates. All the PJM power price and load data used in this analysis comes from www.pjm.com

[6] With natural gas prices at Henry Hub (and associated NYMEX futures prices) continuing to increase in 2005 with spot and forward prices often well in excess of $6/MMBu. Very recently (presumably and hopefully transient) $10+/MMBtu pricing has been observed resulting largely from the damage (physical and perhaps also psychological) caused by recent hurricanes in the Gulf Coast. We focus on 2004, because we are interested in understanding potentially sustainable value, and these natural gas prices are at least anchored to some degree by potential economic costs of LNG in the United States (though, admittedly, this assumes a reasonable competitive market – which is arguably not the case for the crude oil) – though see also discussion of value from risk mitigation against market disruptions.

[7] Depending on assumptions about the device's efficiency, costs, and other factors.

[8] The delivered price of gas will generally be higher in PJM – though strongly correlated to Henry Hub prices – due to a "basis" differential that reflects additional transportation costs from major gas sources, such as the Gulf and Western Canada. Gas transmission constraints can lead to increased basis differentials and volatility.

value of storage. This is because a $1/Mcf increase in gas prices will lift the peak price more than the off-peak price, due to the better heat rate/efficiency of the off-peak units.

Thus, storage will be more valuable in regions where large amounts of nuclear power, hydro and (to a lesser degree) coal are available for off-peak power generation (see Figure 2).[9] Because higher peak power prices tend to increase the arbitrage value for storage, the distance from gas sources can also be a factor because of locational gas price differences (known as "basis" differentials) reflecting implicit transportation (and/or gas storage) costs.

Figure 2: Impact on Relative Change in Value of Storage with Increase in Gas Price
(By Off-Peak Fuel Type (and hence Region)) – Impact of moving from $4 to $6/MMBtu

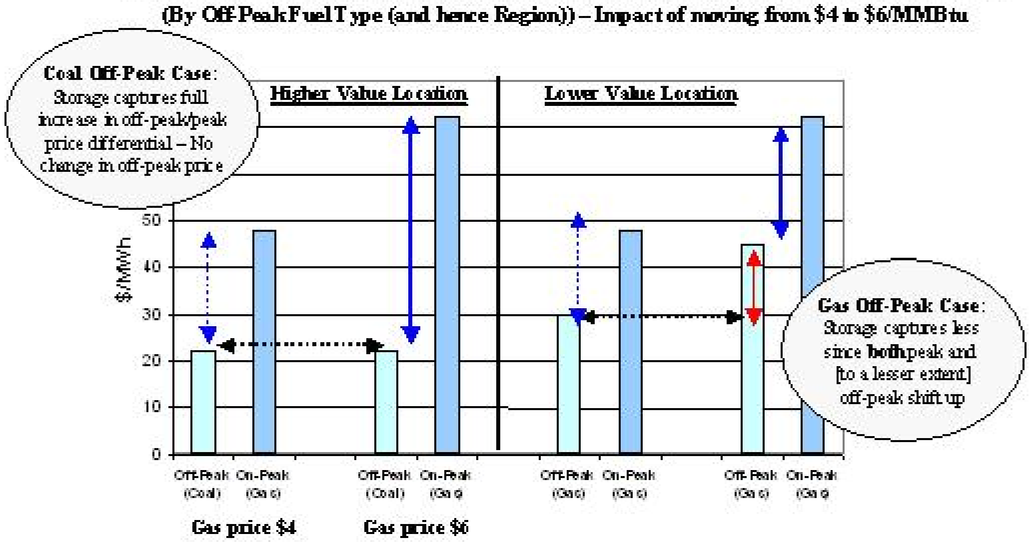
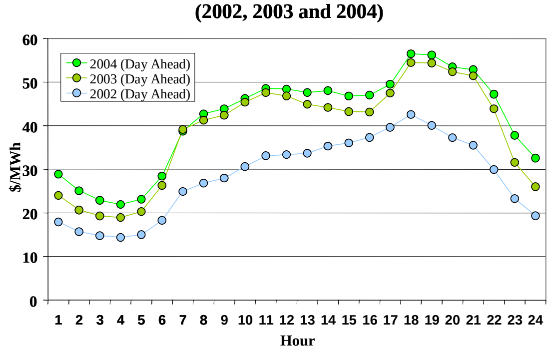
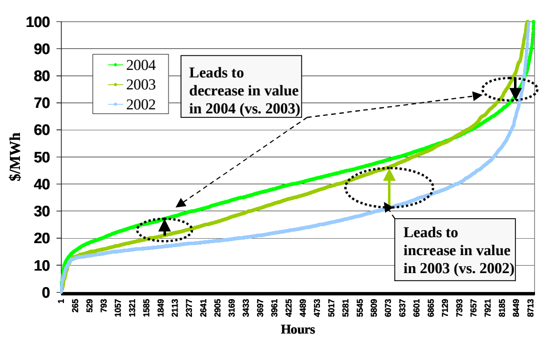


Figure 3 shows the changes in PJM prices and price-duration curves for 2002, 2003, and 2004 used for a "simple rule" and price-duration curve analysis of storage arbitrage value for 2002, 2003, and 2004.[10]

Figure 3: Average Hourly Prices (LMP) for PJM (2002, 2003 and 2004)



Price Duration Curves for PJM (2002, 2003 and 2004)



[9] Figure 2 simplifies the situation, because it assumes coal prices are unaffected by changes in the price of gas. This may not be the case – e.g., see discussion of reasons why the value storage fell in 2004 in PJM.

[10] A very "simple rule" could discharge into the highest priced 8 hours and charge during the lowest priced 10 hours on a daily basis throughout the year (see Figure 3(a)). In the presentation, more sophisticated "simple rules" were used where different operating behavior for weekends vs. weekdays and seasonal effects were assumed. Price duration curve estimates were done on a monthly and two-weekly basis.

The increase in the value of storage between 2002 and 2003 can be clearly linked to the significant increase in power prices during the peak periods – which is to be expected given the large increase in natural gas prices in 2003. Despite further increases in the average price of natural gas in 2004, the value of storage actually fell relative to 2003. There are a number factors contributing to this, including a reduction in gas price volatility, discussed below. Principally, while peak prices increased slightly on average (as did the price of natural gas), average off-peak power prices increased significantly and the occurrence of price extremes (and volatility) decreased (see Figure 3). While these observations can explain the decrease in storage value in 2004, they do not fully explain <u>why</u> off-peak prices increased. More work needs to be done in this area, but there are a number of factors that are consistent with these changes. Coal prices in PJM rose substantially by more than 20% between 2003 and 2004,[11] and this would be expected to increase off-peak prices and hence reduce the value of storage. More generally, and related, is the fact that the "game" keeps changing. In 2004, in particular, the size of the PJM market increased significantly (both in area covered and MW added) – and, consequently this would be expected to lead to changes in demand profiles and generation mix, both of which would be expected to affect off-peak prices even without a change in gas prices.[12]

The Impact of Storage Amount on the Value of Storage
As the amount of storage in a system increases, the arbitrage value on a $/kW-yr basis will decrease as increasing amounts of peak load are shifted to off-peak periods, resulting in higher off-peak and lower on-peak prices, thus reducing the marginal arbitrage value of an extra unit of storage. The net result will be a flattening of both the hourly load profile and the hourly price profile for each day. Theoretically, entry by storage devices should occur until all profitable opportunities to buy cheap off-peak and sell high on-peak are arbitraged away.[13] While the arbitrage value is, therefore, reduced with increasing amounts of storage in a given system, there are a number of significant benefits gained as a result of the load-shifting impact of the storage device. These include:

1. <u>Increased Consumer Surplus</u>: Reduced prices to end users because of significant shifts in consumer surplus from producer surplus.
2. <u>Deferred T&D:</u> Increased societal benefits because of improved utilization of the transmission system and the related deferred need to build more transmission.[14]

Figure 4 shows the shifts of surplus when the amount of storage results in changing peak and off-peak prices.[15] The increase in consumer surplus while discharging during an on-peak period comes from lower on-peak prices at the expense of the producers' surplus. This net surplus shift generally exceeds the shift in the opposite direction that results during charging because of increasing off-peak prices, leading to a net gain to the consumer and loss to the producer. While such a shift leads to lower averages prices for end users, careful attention must be paid to the impact of a flattening price profile on generators' ability to recover their costs in a perfectly competitive wholesale market for electricity and resulting long-run impacts on generation entry and exit. On the other hand, substantial amounts of storage would also make the exercise of supplier market power more difficult. Storage would essentially make on-peak demand more elastic, thus increasing the cost of exercising market power and thus reducing the benefits of doing so. The net impact of both tendencies on the societal desirability for large amounts of storage in a given electrical system will depend largely on the specifics of the system considered – fuel mix, demand profiles, supply-demand mix, market structure.[16] There are also further related risk-management benefits, in that storage can mitigate against potential adverse impacts of market failure and market disruptions.[17] Finally, Figure 4 also shows that there is a reduction in the arbitrage revenue (partly offset by increased charging costs) that should benefit consumers (at least in the short run).

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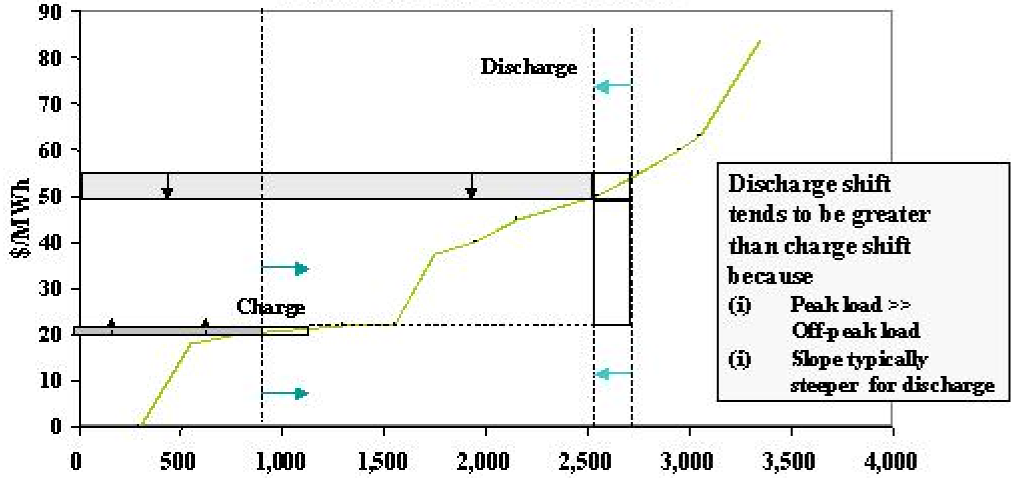
[11] PJM 2004 Market Monitoring Report.
[12] Other potential effects are competitiveness of the market/premiums and the weather.
[13] Though this would have to include covering the capital cost of the device and obtaining a reasonable return on an expected basis – something not considered feasible from arbitrage-only considerations.
[14] Also increased societal benefits because of improved utilization of the generation system, and the related deferred need to more generation.
[15] Using an illustrative generation supply curve and assuming inelastic demand.
[16] And hence needs to be informed by detailed empirical analysis we have not performed at this point.
[17] Surplus shift arguments tend to assume that the markets are in equilibrium. In the real world, there may be real value from a risk-management perspective in using such devices to mitigate the impact of market failure (e.g.,

The non-arbitrage-related benefits are less controversial because they are additive values to society: It is almost self-evidently good that load shifting leads to the more efficient utilization of existing transmission and generation assets. [18] However, the value of storage from this perspective varies widely:

- For an underutilized line, there is little economic value;
- For a full line, it has value immediately against future load growth;
- For an "overfull" line device, it can also relieve "congestion" cost.

Moreover, the cost – as distinct from value – of building transmission can also vary widely on a per-MW basis, depending on how long the line needs to be. More generally, the value of storage in providing this peak-load shifting service needs to be set against the cost of the next-best alternative, including potential transmission upgrades and/or additions, the use of distributed generation and/or load management, or some combination of the above, including storage.[19]

Figure 4: Shifts in Consumer and Producer Surplus during Storage Discharge and Charge Periods



Note: Charge increased by 1/ η to reflect effect of efficient loss during charge discharge process – Alternatively same MW for charging and discharging but 1/ η times the discharge period

Ownership and Market Structure

One of the common complaints and/or concerns of potential investors in storage devices is that while storage generates a variety of value streams, these value streams are (i) either not paid for and/or (ii) paid to the wrong person. Moreover, different market participants (e.g., private investor, utility generator, transmission operator/ISO, and customer) have very different interests and incentives.

California power prices without price caps) or market disruptions (e.g. recent hurricanes). For example, in the case of increasing gas prices because of a severe supply disruption – such as experienced recently due to hurricanes in the Gulf, large amounts of storage would be expected to reduce peak load, peak prices, and gas use (and prices). The benefits of reduced price increases would benefit society by lowering prices to consumers (relative to what they would have otherwise have been) and limit "windfall" gains to producers.

[18] Some studies put the value of forgone transmission build/upgrades due to storage at $400/kW in some instances; though, as these authors note, potential value is extremely site specific. See e.g. Iannucci, Joe and Eyers, Jim, *Technical and Market Aspects of Innovative Storage Opportunities*, DOE Annual Peer Review. November 20, 2002.

[19] This paper has focused on the value of storage and, in many senses, has been deliberately agnostic about what particular technology might provide large-scale storage. One interesting avenue currently being considered by some is the use of vehicle-to-grid hybrid-electric vehicles – though the initial focus of some of this analysis has been on the provision of ancillary services.

For example, a private investor building a small device for arbitrage may result in few short-term benefits for customers as the arbitrage value is captured by the owner of the storage device. However, as discussed at the beginning of the paper, arbitrage value alone may not be sufficient to justify private investment in storage; but a private investor will find it difficult to capture additional benefits provided by storage such as deferred investments in transmission. In a market like PJM, where a significant percentage of transactions clear at the spot market price, a private investor may not have the incentive to build the socially optimal amount of storage, because this may lead to peak load (and price) shifting, which will literally "kill the golden goose." The incentives for a Genco, i.e. a company with a portfolio of power plants, to build (and subsequently operate) large amounts of storage could be even worse. If a Genco with no market power built a large amount of storage, it would lower prices received by all of its generation assets on-peak more than it would increase its revenues off-peak.[20] If it had market power prior to building a large amount of storage, its ability to profitably exercise this market power would be curbed by the opposing incentives created from its storage facilities, much like Gencos with load-serving obligations have lower incentives to exercise market power than those who do not. So while from society's perspective it may be desirable for a Genco to build large amounts of storage, the incentives for a Genco to do so are likely significantly lower. The incentives are significantly different for a transmission operator or ISO, where the storage device could be considered a regulated asset. Both arbitrage benefits and transmission deferral benefits could be partly passed on to end users (beyond revenues necessary to pay for the device (which will depend partly on whether the entity is a not-for-profit or profit-driven entity). The Transco/ISO would also potentially see load- and peak-price shifting as desirable and have no regrets about lost arbitrage. In its mix of options to operate wholesale markets and transmission systems, storage could be recognized as a lower-cost potential alternative to transmission expansion, reliability enhancer, or reserve provider and may actually lower the overall cost of providing the coordinating functions provided by the ISO/Transco. This is an area that could benefit from further analysis.

Summary

The approach discussed here is intended to contribute to providing a framework for thinking about a number of storage-related issues. Our analysis was considerably simplified by "collapsing" and using a representative price for large region. A more detailed study of PJM (and other regions) would need to work at a "lower level" to take account of regional differences, locational marginal prices, congestion costs, and other factors. Large amounts of storage might turn out to be quite small within this context. Some key insights, many of which are already generally known, are:

- Value of storage from arbitrage has increased in PJM since 2002, because of increases in natural gas prices – with recent power prices supporting \$50 to \$70/kW-yr, or more in PJM:
    - Decrease in 2004 vs. 2003 may be partly due to rises in coal prices in PJM in 2004.

- Value drivers of storage (not all independent) include:
    - Increased gas price volatility and, hence, power price volatility
    - Increased gas prices and, hence, increased peak power prices (when gas is on the margin)
    - Increased distance from a gas supply source (and higher gas prices due to basis)
    - Off-peak load served by nuclear, hydro, and (to a lesser degree) coal
    - Transmission congestion.

- Large amounts of storage present challenges and opportunities relative to small amounts
    - Reduced arbitrage to private owner
    - Large shifts in consumer and producer surplus leading to lower prices to consumers – at least in the short-term. Also short-term risk management benefits from mitigation against market disruption and market failure
    - Better utilization of existing T&D can be of significant value e.g., against deferred transmission – but must look at next-best alternative to assess true economic value.

- Value capture depends on ownership and market structure. Incentives for private investor vs. Transco/ISO are very different.

[20] This assumes an unregulated Genco.