Energy Choice Matters

February 20, 2009

FirstEnergy Files ESP Settlement With Many Nonbypassable Fees, but No Standby Charges

A proposed settlement among the FirstEnergy Ohio utilities, PUCO Staff, and industrial customers to establish an electric security plan would remove a nonbypassable minimum default service charge and would create an opportunity for government aggregators to match any generation rate increase deferrals approved by PUCO, but the Ohio Consumers' Counsel and NOPEC says the plan would still potentially impede the opportunity for governmental aggregation. The electric security plan would contain a host of nonbypassable charges, including fees for previously deferred generation and transmission costs, and for deferrals of purchased power costs for Cleveland Electric Illuminating customers through May 2009. Constellation NewEnergy and Integrys Energy Services signed the stipulation as non-supporting/non-opposing parties.

Under the proposal, Standard Service Offer (SSO) supplies from April 1 through May 31, 2009 would be sourced by affiliate FirstEnergy Solutions, and priced at the at the average wholesale rate from the interim supply RFP ($66.68/MWh), adjusted for line losses. The distribution utilities would remain as the Load Serving Entity for Midwest ISO purposes during this period, and would incur various costs to serve such load, which would be recovered via the transmission rider.

At CEI, PUCO's previously approved deferral of purchased power costs would continue for April and May 2009, with carrying charges. Recovery will be charged to all CEI customers as a nonbypassable rider starting June 1, 2011, for a period up to 10 years.

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PUCT's Anderson Says Miscellaneous Gross Receipts Tax Should be Line Item

After further review and discussions with REPs, the Texas Miscellaneous Gross Receipts Tax (MGRT) should not be bundled into the per-kWh price quoted by REPs on Electricity Facts Labels, PUCT Commissioner Kenneth Anderson said in a memo in advance of today's open meeting (35768).

The issue relates to new rules for customer disclosures, which were generally approved by the Commission at the last open meeting, but not yet finalized in a written order (Matters, 1/30/09).

The Miscellaneous Gross Receipts Tax is imposed on companies making local sales of electricity within an incorporated city or town having a population of more than 1,000, and the rate varies depending on the population of the city where the meter is located (up to 2%).

Anderson originally believed that the Miscellaneous Gross Receipts Tax should be included in the per-kWh price to permit an apples-to-apples comparison among offers, and to reduce unexpected charges appearing on bills.

However, as the tax rate varies by location, bundling it into the per-kWh price could result in higher prices for some customers who reside outside of jurisdictions subject to the Miscellaneous Gross Receipts Tax, Anderson said. REPs would likely estimate the inclusive price at the highest tax rate for everyone, thereby diminishing the tax savings that customers residing in

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Modest Increase Seen in Delaware Large C&I SOS Rates

Residential and small commercial rates for Delmarva Delaware customers will remain flat for the next year, while medium commercial prices will fall about 2%, and large commercial prices will rise about 5-6%, based on results from an auction for SOS supplies for the year beginning June 1, 2009.

Though average winning bid prices were released, Delmarva typically files updated retail rates in April. Bid consultant Boston Pacific provided rate projections in a report on the procurement, which moved to a descending clock auction this year from a sealed-bid RFP format.

For the combined Residential and Small Commercial class, Delmarva sought 36-month contracts accounting for approximately 33% of SOS needs. The average winning load-weighted price for the mass market class was $103.49/MWh, about 6% lower than bids last year. However, the price is about the same as the price supplied in the 2005-06 RFP which is being replaced, so rates will remain about the same.

All other classes are served under one-year contracts for 100% of load. For the Medium General Service class, the wining price was $98.95/MWh, while the Large General Service (Secondary) class had a wining price of $103.33/MWh. The General Service – Primary class had a winning price of $101.97/MWh.

Of 11 registered bidders, only nine bid, versus 11 bidders of 12 registered in the 2007-08 auction. Of the nine bidders this year, six won a portion of Delmarva's SOS needs. The winning suppliers were: Consolidated Edison Energy Inc; Conectiv Energy Supply Inc; Constellation Energy Commodities Group; Hess Corporation; Macquarie Cook Power Inc. and PPL EnergyPlus LLC

Two other suppliers (NRG and DTE Energy) will continue to serve previously won mass market load. The breakdown of total 2009-10 load served is:

Conectiv	12%
ConEd Energy	13%
Constellation	12%
DTE Energy	4%
Hess	33%
Macquarie	4%
NRG	8%
PPL EnergyPlus	12%

Delmarva acquired a total of 604.8 MW of Peak Load for full-requirements SOS service.

Boston Pacific does not see any immediate need to significantly change the SOS process, but suggested reviewing: coordinating procurement efforts with other jurisdictions; the effects of increased separate renewable (particularly wind) contracting on auction participation, decreased demand (due to the recession) on participation; and potential changes to the SOS product to increase bidder participation.

Delmarva recently signed four long-term PPAs to supply wind power, and Boston Pacific encouraged the PSC to examine (to the extent not already done so) whether the contracts will make load following for SOS suppliers more difficult, and possible mitigation of such effects to the extent possible.

Boston Pacific recommended that the PSC reconsider current collateral requirements as a potential means by which to lower bid prices. The collateral that bidders need to post could be capped at a specific dollar amount or percentage of the contract value, which could limit bidders' potential credit costs and lower bid prices, Boston Pacific said. Currently, there is no limit on the amount of collateral bidders may have to post. "This may be a concern to bidders as the past year has shown prices to be far more volatile than most people suspected," Boston Pacific said.

Additionally, PJM is preparing to move to weekly billing beginning in June 2009. That creates something of a mismatch with the Full Requirements Service Agreement (FSA) that all winning bidders sign with Delmarva, which pays suppliers monthly. The mismatch can create a credit need for a supplier, which could increase costs. Boston Pacific suggested Delmarva investigate the effects of weekly PJM settlement on bidder costs, and also look into possible remedies.

The Commission may want to investigate

whether there are ways to structure the full requirements product so as to increase bidder participation, such as breaking up the full requirements product into component products (e.g. energy, capacity and ancillary services) in an attempt to get more competitors and lower prices, Boston Pacific said.

FERC Denies Midwest ISO Market Service Proposal, Cites Degradation to Order 2000

FERC rejected the Midwest ISO's Market Service Proposal, which would have extended the benefits of LMP markets to utilities not joining MISO as transmission owners, citing the potential harm to customers (ER08-637).

The proposal was designed to allow new MISO participants to sample the MISO energy markets without exposure to regional transmission cost sharing. MidAmerican Energy expressed the most firm interest in becoming a Market Service customer (Matters, 11/13/08).

FERC first held that the Market Service proposal must be judged in light of Order 2000, which sets minimum requirements for RTOs, including sufficient size and scope to reduce pancaking and avoid "holes" in the RTO's footprint. The Commission rejected MISO's argument that Order 2000 did not apply since the proposal is not for a start-up RTO.

Echoing concerns raised by several market participants, FERC agreed that the Market Service proposal, when combined with concerns about regional cost sharing, could result in current Transmission Owners leaving the Midwest ISO Transmission Owners Agreement to take Market Service. "Such departures would adversely affect Midwest ISO's scope and configuration under Order No. 2000, and its ability to perform regional transmission operations," FERC held.

Further, FERC noted there is concern that the proposal would create a disincentive for remaining Midwest ISO Transmission Owners to invest in certain high voltage transmission projects if those Transmission Owners believe that such costs are not being properly assigned to beneficiaries.

If signatories to the Transmission Owners Agreement exit Midwest ISO and instead take Market Service, there would be increased levels of rate pancaking, reduced independent regional planning, reduced independent tariff administration, and an increase in the number of OASIS sites, FERC said. "Accordingly, the proposal could cause adverse impacts on the efficiency of whole markets and on Midwest ISO's ability to address operational and reliability issues and to eliminate any residual discrimination in transmission services." the Commission ruled.

FERC was not convinced that the proposal represented a "transitional" mechanism that would facilitate new transmission-owning members in MISO, stating MISO did not show how the proposal would resolve current barriers to greater RTO participation among those who currently choose not to join.

WMECO Files Basic Service Rates for Larger C&Is

Western Massachusetts Electric Company filed with the DPU basic service rates for medium and large C&I customers for the period April 1 through June 30, 2009. The rates below reflect the Default Service Cost Adjustment and Uncollectible Tracker amount of $0.00129 per kWh.

Monthly Rates

April	$0.07576 per kWh
May	$0.07494 per kWh
June	$0.07967 per kWh
Fixed Price Option	$0.07679 per kWh

Medium and Large C&I rates apply to customers on rates G-2, T-4, T-2, I-1, I-3, PR and Contracts.

Md. Staff Favor 423 MW of Gap Load Response

Although Maryland PSC Staff conceded there may be a reduced need for demand response procured via utility RFPs to fill a once-forecast gap in Maryland reliability in 2011-12, the relatively low cost of the gap "insurance" favors Commission approval of most of the load response offered in the RFP, Staff said (Case 9149).

Accepting 423.4 MW of load response -- of the 539 MW offered for 2011-13 -- would only impose a "modest" monthly bill impact of about 12-17¢ on residential customers. Approving only the lowest-cost bids, representing 110.4 MW for the critical summers, would only reduce unit costs by a small amount, while reducing capacity procured by a factor of four. Meanwhile, procuring all offered load response would increase total cost by two-thirds, but would only add 116 MW of capacity.

"The foundation of the Gap RFP has always been its use as a low cost reliability 'insurance policy' to address the unavoidable uncertainties of major transmission project construction and changes in system demand," Staff said, arguing the risks of over-procuring capacity at a modest cost are superior to the risk of a capacity shortage.

Still, Staff agreed several factors likely reduce the projected gap, if any remains, which led other stakeholders to recommend procuring zero resources. First, a proposed PJM settlement on changes to the Reliability Pricing Model pending at FERC would allow PJM to implement incremental RPM auctions for backstop supplies should shortages be forecast, which would spread backstop capacity costs over all PJM load, not just Maryland customers.

The current economic climate has reduced load forecasts as well, plus Maryland, and other PJM states, continue to implement energy efficiency measures further reducing demand. Backbone transmission projects meant to meet the originally projected increases in demand in 2011-12 continue to move forward as planned, Staff noted.

For those reasons, both Baltimore Gas and Electric and the Office of People's Counsel argued that unless a proven reliability need is found, the PSC should not contract for any of the load response offered in the RFP. OPC suggested a future gap procurement should be done sometime after the May 2010 RPM base auction for the 2013 delivery year, which would inform the Commission on whether a gap still exists.

Conn. DPUC Sees No Procurement Need in IRP

A final Connecticut DPUC integrated resource plan affirms a draft finding that no new supply procurement is needed since there is no current or projected reliability need, but does open the door for future procurements for policy reasons other than reliability (Matters, 1/19/09).

The Connecticut Energy Advisory Board (CEAB), in concert with the distribution utilities, developed an IRP that favored heavy expenditures into demand-side management and conservation, and also supported greater bilateral and long-term contracting for utility standard service supplies, as well as bundled energy, capacity and REC contracts (08-07-01).

Since the record shows no forecast reliability need, the DPUC declined to order any procurement of resources.

However, in the future, the Department may in its discretion approve procurement plans even absent a reliability need, if it deems such procurement to be in the public interest by lowering costs or improving environmental quality. Projects would have to demonstrate that: 1) the proposal requires ratepayer funding and cannot be supported by market revenues, direct participant funding, or private investor funding; 2) there is a great degree of certainty that the proposal will substantially reduce costs or produce savings for ratepayers that exceed the cost of ratepayers' investment or substantially improve the environment and any near-term rate increases do not cause substantial hardship to ratepayers; and 3) (a) the products or services offered in the proposal will count toward satisfying Connecticut's energy or capacity requirements, (b) can displace some existing older, more expensive, less efficient, more polluting resources, or (c) can reduce the future need for additional resources to meet Connecticut's requirements.

Waiting until there is a reliability need may not provide enough time to put the best projects in place to meet long-term objectives and could result in the reliance on an electric system that is far from optimal, the DPUC observed, noting several older units may be due to retire soon. Still the IRP, "cannot become an endless annual proceeding in which every project that can provide some benefits to ratepayers is examined," as projects will have to meet the criteria enumerated above. The Department will require a "high standard" to justify the procurement of additional resources if there is not a reliability-based need in the near or intermediate term.

Many of the CEAB and utility recommendations could move Connecticut away from a market-based industry structure, which the Department was unprepared to do absent further direction from the legislature. "It is important that development of resources, long-term contracting by the EDCs and other recommendations be examined in the context of our electric industry/regulatory paradigm and consider any changes that could result," the DPUC said.

The Department directed the utilities and CEAB examine and make recommendations aimed at maximizing the consistency and coordination of standard service, provider of last resort and other Department procurement efforts with their needs assessment and procurement plan.

The DPUC was not persuaded to make any changes in its recent policies regarding long-term bilaterals for standard service (capped at 20%), or renewable bilaterals (which are limited to RECs only and cannot bundle energy, capacity and RECs). There is no guarantee that long-term contracts will reduce electric rates, and long-term contract prices may be higher than market prices for many years, putting ratepayers at risk for higher rates and stranded costs, the DPUC said.

The record shows that there will be sufficient renewable resources in the near-term, and the Department declined to order additional renewable procurements, though utilities currently have the flexibility to solicit REC-only contracts. Additionally, to the extent utilities select renewable developers as part of their 20% carve-out for long-term standard service bilaterals, such procurement could include renewable generation under bundled energy/capacity/REC contracts, the DPUC said. However, a separate authorization to enter into bundled REC and energy contracts outside of this process is not permitted.

FERC Won't Replace PJM Three Pivotal Supplier Test, But Finds Current Mitigation Unjust

FERC found that there was not sufficient evidence to find that use of the three pivotal supplier test for market power mitigation in PJM is unjust and unreasonable, but did rule that the application of related price mitigation measures is unjust and unreasonable, because the measures do not clearly define and fully account for the inclusion of unit-specific opportunity costs in mitigated offer prices (EL08-47).

For most suppliers that fail the screen, the mitigated offer price is the incremental operating cost plus a 10 percent adder (the default bid). However, opportunity costs are not specifically provided for or clearly defined in the default bid, FERC said, and the current provisions for including such costs are limited to a case-by-case process. Opportunity costs are especially not accounted for in energy- and environmentally-limited resources.

Default bids that do not account for opportunity costs can lead to inefficient use of scarce resources and increased costs to customers, FERC noted.

While FERC found current mitigation to be unjust, parties have not made specific proposals for just and reasonable alternatives. FERC therefore directed PJM to file a proposal to incorporate opportunity costs in mitigated offers by July 31, 2009.

Various parties addressed the interaction of the three pivotal supplier test and scarcity pricing in the docket. However, because FERC has since issued Order 719 which directs RTOs to review existing scarcity rules to demonstrate their adequacy or propose reforms, FERC declined to address scarcity pricing in the pivotal supplier docket.

Briefly:

Start-up Palmco Power to Serve Connecticut Mass Market

Palmco Power CT, LLC applied for a Connecticut electric supplier license for all customer classes at the DPUC. Principal Robert Palmese has worked for family-owned New York electric and gas ESCO (and fuel oil supplier) Columbia Utilities. Palmco projected first-year sales of 2,000 MWh, with a customer base of 110 customers (100 residential).

TXU Terminates Parts of Capgemini Contract

TXU Energy terminated certain aspects of a contract to outsource several customer service functions, including call center and billing remittance services, to Capgemini Energy effective January 19, it reported to the PUCT. TXU is moving those processes back in-house, or to subcontractors who performed the services under Capgemini.

PUCT Staff Clears Hudson Energy JV Name

PUCT Staff revised its recommendation on the sufficiency of an application from Hudson Energy JV for a REP certificate, stating its initial concern about the REP's duplicative name has been resolved (Matters, 2/17/09). Staff believes that Hudson Energy JV's affiliation with Hudson Energy Services makes its concerns regarding P.U.C. Subst. R. §25.107(e)(1) requirements moot because the applicant Hudson Energy JV is wholly owned by the parent company Hudson Energy Services, which currently holds a REP certificate. P.U.C. Subst. R. §25.107(e)(1) prohibits applicants from using names duplicative of those already certified, or otherwise deceptive or misleading. Staff's recommendation was limited to the sufficiency of Hudson Energy JV's application, and did not address not its merits.

Poco Seeks to Aggregate Texas Customers Again

Poco Energy Group, a subsidiary of Summit Energy Services, applied for an aggregator license at the PUCT. The broker previously held an aggregator certificate from 2001-2006, but relinquished it as customer demand for aggregation waned. Poco would pool C&Is, and indicated it expected to mostly aggregate large commercial real estate properties, hotels and restaurants. Poco currently brokers in Maryland, Illinois, New York, New Jersey and Massachusetts as well.

FERC OKs Anchor Customer Approach at Two Merchant Transmission Lines

FERC allowed two merchant transmission developers to use an “anchor” customer model for allocating grid capacity, in which each developer contracted with a wind generator for half of the capacity on its line, in a move that marks a new flexibility in FERC policy directed at merchant transmission projects (ER09-432). The Commission approved negotiated rates for Chinook Power Transmission and Zephyr Power Transmission for their 1,000-mile projects from wind farms in the Northern Rocky Mountains to a point near Las Vegas, Nev. FERC modified its "unduly rigid and inflexible" requirement for a 100% open season to allocate transmission capacity in the case, but said it would address open season requirements on a case-by-case basis. FERC will apply a higher level of scrutiny when affiliates of the merchant transmission developer are anchor customers due to the absence of arms’ length negotiations as a basis for the commitment. The case may be instructive for a current request by Nstar and Northeast Utilities to build a transmission line into Quebec to support a hydropower PPA. The utilities have said the project is not a merchant line, though other stakeholders have challenged that claim (Matters, 1/27/09).

FERC Directs MISO to Share Marketer Resource Adequacy Data with States

FERC granted a protest from the Illinois Commerce Commission regarding a Midwest ISO compliance filing for its resource adequacy construct which will allow state regulators to access resource adequacy data for competitive suppliers, not just IOUs (ER08-394-005, Matters, 12/8/08). MISO's originally approved Module E resource adequacy mechanism required MISO to submit data to state regulators validating LSEs' planning resources and obligations upon request. Cooperatives requested that since they are not regulated by state authorities they should be excluded. FERC granted the request, but in its compliance filing, MISO used language which made the reporting requirement only applicable to rate regulated LSEs, which would prevent regulators from accessing information on competitive suppliers' planning resources. The ICC objected, and suggested that the MISO modify Module E so that rate regulated entities, and entities which use delivery services set by state regulation, would be subject to the disclosure requirement, to cover competitive suppliers FERC granted the request.

FERC Approves Duke Ohio Generation Transfer

FERC approved the transfer of former Cinergy plants from Duke Energy Ohio to new merchant entities. The plants had never been in Duke Ohio's ratebase, and the transfer was agreed to in a settlement regarding Duke's electric security plan.

FERC Approves CAISO Exceptional Dispatch

FERC yesterday said it concluded an investigation into the Exceptional Dispatch provisions of the California ISO's Market Redesign and Technology Upgrade (MRTU) tariff, finding the proposal to be a just and reasonable mechanism for maintaining grid reliability under MRTU. A written order was not available yesterday. But the Commission also rejected in part the proposed mitigation measures upon finding that the CAISO failed to show the potential to exercise market power, with two limited exceptions. Finally, pursuant to section 206 of the Federal Power Act, the Commission imposed a revenue cap on Exceptional Dispatch revenues during a four month transitional period following the implementation of MRTU to help facilitate a smooth transition to the new market.

FERC OKs EDF Stake in Constellation

FERC yesterday authorized EDF's $4.5 billion purchase of an ownership interest in the nuclear generation and operations business of Constellation Energy Group. The Commission also approved the terms of an agreement that gives Constellation Energy the option but not the obligation to sell its ownership interests in various non-nuclear generating plants and certain associated jurisdictional assets to EDF Development at agreed prices aggregating up to $2 billion.

FirstEnergy *... from 1:*

For the period beginning June 1, 2009 and ending May 31, 2011, retail generation rates will be determined pursuant to the results of a descending-clock competitive bid process. In the competitive bid process, the utilities would procure, on a slice of system basis, 100% of the aggregate wholesale full requirements SSO supply, which includes energy and capacity, resource adequacy requirements, transmission service and transmission ancillaries. Bidding would be for a single two-year product, and the bidding process would not be subject to a load cap for bidders. FirstEnergy Solutions may participate in the bidding.

As transmission would be part of the product procured in the auction, the transmission rider after June 1, 2009 would be set at zero, except for reconciliations.

For generation rates starting June 1, 2009, the settlement would permit PUCO to phase-in rates at PUCO's discretion in an amount not to exceed, in the aggregate for all three utilities, $300 million in 2009, $500 million in 2010, and $200 million in 2011. Purchased power costs equal to the amounts constituting a phase-in discount will be deferred, and collected through a nonbypassable rider, except certain governmental aggregations could avoid the rider. Cost recovery, which would include carrying charges, would occur over a period up to 10 years starting June 1, 2011.

FirstEnergy would offer an opportunity for governmental aggregations to defer their customers' generation costs in an amount equal to the credits provided to SSO customers. Under the proposal, for every kWh of energy that a Governmental Aggregation Generation Supplier delivers to a customer of a governmental aggregation group that elects the phase-in, the Supplier will be granted the right to receive from the utilities a deferred amount equal to the phase-in generation credit received by the aggregation customer, plus carrying charges.

Generation price increases for the large commercial and industrial customer classes, as well as for private outdoor, street and traffic lighting, would be limited to one-and-a-half times the average increase in the utilities' original ESP proposal. Qualifying schools would also receive discounted rates. Recovery of lost revenues from such mitigation would be recovered on a nonbypassable basis from General Service Secondary and General Service Primary customers. A nonbypassable surcharge would also recover any lost revenue created by "reasonable arrangements" or other special economic development rates charged to certain industrials.

Deferred 2006 and 2007 fuel expenses and associated carrying charges would be recovered over 25 years via a nonbypassable surcharge, though at an amount $10 million less than the December 31, 2008 balance. Recovery of previously deferred incremental transmission and ancillary service-related charges would commence April 1, 2009 and end December 31, 2010, pursuant to a non-bypassable Deferred Transmission Costs Recovery Rider.

The electric security plan would not include a minimum default service rider or standby charges as originally proposed by FirstEnergy. Rate Stabilization Charges would also cease starting June 1, 2009, and there would be no shopping credit caps. The ESP would not impose a minimum stay for residential and small commercial non-aggregation customers.

The FirstEnergy utilities would meet renewable requirements through a separate RFP process to obtain RECs. REC charges would be recovered through a bypassable rider.

A bypassable Generation Service Uncollectible Rider would be established to recover reasonably incurred generation uncollectible costs. Such a rider, effective April 1, 2009 on a service rendered basis, would initially be set at the average rate of .0403 cents per kWh (composite of all companies) but shall be reconciled quarterly to reflect actual uncollectible generation costs incurred after December 31, 2008.

According to the stipulation, a nonbypassable Generation Cost Reconciliation True-up rider would be established to implement reconciliation of seasonal generation cost recovery and to recover the difference between amounts paid to suppliers and amounts actually billed to customers.

FirstEnergy would write-off 50% of the extended Regulatory Transition Credit balance at CEI, or about $215 million.

In order to ensure continuation of SSO supplies, FirstEnergy said that parts of the ESP, including the supply mechanism for April and May 2009, must be approved by March 4, 2009, or FirstEnergy may withdraw the ESP. FirstEnergy has scheduled a March RFP solicitation for interim supplies if the ESP is not approved (Matters, 2/19/09).

MGRT *... from 1:*

unincorporated areas enjoy. This is particularly true because the Power to Choose website lists prices based upon particular TDU service areas, rather than smaller geographic regions such as cities.

Thus, the Miscellaneous Gross Receipts Tax should be listed as a separate line item on bills, similar to state and local sales taxes, Anderson concluded.

Anderson stressed, however, that charging the tax as a line-item should not be seen as an invitation for REPs to "over collect" the Miscellaneous Gross Receipts Tax. While REPs are allowed to request reimbursement for the tax from the customer, they are required to include the amount of the reimbursement as part of the gross receipts received when computing the tax, which essentially taxes the reimbursement.

Thus, if a REP chooses to seek reimbursement for the Miscellaneous Gross Receipts Tax, Anderson does not believe that the REP may collect more than the state imposed percentage in the separately listed charge; REPs cannot "gross up" the Miscellaneous Gross Receipts Tax by some amount designed to mitigate the "tax on tax" problem.

"Any attempt to do so will be a deceptive practice, at least in this Commissioner's opinion," Anderson said, and he requested Enforcement Staff periodically review REP bills to see whether REPs that break out the Miscellaneous Gross Receipts Tax are being deceptive and manipulative in their Miscellaneous Gross Receipts Tax billing.