FINAL ADMINISTRATIVE DECISION
ILLINOIS PROPERTY TAX APPEAL BOARD

APPELLANT: Grand Tower Energy Center, LLC
DOCKET NOS.: 14-03445.001-I-3 through 14-03445.009-I-3 and 15-00452.001-I-3 through 15-00452.010-I-3
PARCEL NOS.: See Below

The parties of record before the Property Tax Appeal Board are Grand Tower Energy Center, LLC, the appellant, by attorney Patrick C. Doody, of the Law Offices of Patrick C. Doody in Chicago; the Jackson County Board of Review by Jackson County Assistant State's Attorney, Daniel Brenner; and Shawnee C.U.S.D. #84, intervenor, by attorney Scott L. Ginsburg of Robbins, Schwartz, Nicholas, Lifton & Taylor in Chicago.

Based on the facts and exhibits presented in this matter, the Property Tax Appeal Board hereby finds ***A Reduction*** in the assessment of the property as established by the **Jackson** County Board of Review for tax years 2014 and 2015 is warranted. The correct assessed valuation of the subject property for each tax year under appeal is:

2014

DOCKET NO	PARCEL NUMBER	LAND	IMPRVMT	TOTAL
14-03445.001-I-3	16-13-100-001	9,740	0	$9,740
14-03445.002-I-3	16-13-300-001	1,909	0	$1,909
14-03445.003-I-3	16-13-300-004	1,338	0	$1,338
14-03445.004-I-3	16-13-300-006	152,052	0	$152,052
14-03445.005-I-3	16-14-200-001	115,807	3,048,882	$3,164,689
14-03445.006-I-3	16-14-200-002	601	0	$601
14-03445.007-I-3	16-14-400-002	1,396	0	$1,396
14-03445.008-I-3	16-23-200-001	766	0	$766
14-03445.009-I-3	16-24-101-001	509	0	$509

Subject only to the State multiplier as applicable.

2015[1]

DOCKET NO	PARCEL NUMBER	LAND	IMPRVMT	TOTAL
15-00452.001-I-3	16-13-100-001	9,740	0	$9,740
15-00452.002-I-3	16-13-300-001	1,909	0	$1,909
15-00452.003-I-3	16-13-300-004	1,338	0	$1,338
15-00452.004-I-3	16-13-300-006	152,052	0	$152,052

[1] The 2015 appeal contains an additional parcel number, PIN 46-13-300-001, which was not appealed in tax year 2014.

15-00452.005-I-3	16-14-200-001	115,807	3,048,249	$3,164,056
15-00452.006-I-3	16-14-200-002	601	0	$601
15-00452.007-I-3	16-14-400-002	1,396	0	$1,396
15-00452.008-I-3	16-23-200-001	766	0	$766
15-00452.009-I-3	16-24-101-001	509	0	$509
15-00452.010-I-3	46-13-300-001	633	0	$633

Subject only to the State multiplier as applicable.

For purposes of this appeal and pursuant to Property Tax Appeal Board Rule 1910.78 (86 Ill.Admin Code §1910.78), Docket No. 14-03445.001-I-3 through 14-03445.009-I-3 was consolidated with Docket No. 15-00452.001-I-3 through 15-00452.009-I-3 for purposes of oral hearing.

STIPULATIONS

Prior to the hearing the parties stipulated as follows:

1) All parties agree the Jackson County Board of Review's final assessed value for both the 2014 and 2015 assessments of the subject property was $31,538,245 for all parcels affected herein. The assessments for both tax years was based on an appraisal submitted by the intervenor to the Jackson County Board of Review. In addition, the Jackson County Board of Review assessed the subject for the previous 2013 year at $33,445,837 for all parcels affected herein which was based on a stipulated value with the previous owner and the intervenor;

2) Kevin S. Reilly, ASA; George K. Lagassa, Ph.D., ASA; Michael E. Green, ASA; and J. Fernando Sosa, ASA, MRICS are identified and recognized as experts in the valuation of the Grand Tower Energy Center;

3) All parties agree that 50% of the improvements at the Grand Tower Station will be considered real property for purposes of taxation under the Property Tax Code 35 ILCS 200/1-1 et. Seq. and 50% shall be considered personal property and not subject to taxation under the Property Tax Code;[2]

[2] Prior to the hearing, the parties stipulated that 50% of the improvements were to be considered "personal property" and not subject to taxation pursuant to the Property Tax Code. This stipulation reflects the past practice of the County Assessor. In 2002, the parties entered into a joint agreement regarding Grand Tower Energy Center, which states that prior to January 1, 1979, 50% of the improvements of the Grand Tower station were classified as real property. Valuing the improvements at half their value is also mandated by the "Freeze Act" (35 ILCS 200/24-5), which states that "no property lawfully assessed and taxed as personal property prior to January 1, 1979, or property of like kind acquired or placed in use after January 1, 1979, shall be classified as real property subject to assessment and taxation. No property lawfully assessed and taxed as real property prior to January 1, 1979, or property of like kind acquired or placed in use after January 1, 1979, shall be classified as personal property."

4) The total assessment for the improvements shall be calculated as follows:

Total Fair Cash Value of All Improvements
x 50.00%
x 33.33%
Assessed Value of All Improvements;

5) Improvements shall mean real and personal property associated with the subject property, including all furniture, fixtures and equipment and machinery and equipment including combustion turbines, steam turbine generators, heat recovery steam generators ("HRSGs"), mechanical equipment, structures and foundations, piping, fire protection, tanks, transformers and substations, accessory electrical equipment, buildings and platforms, land improvements, support buildings and controls and instrumentation all as described on pages 9 and 10 of the January 1, 2014 evcValuation appraisal submitted by the Appellant, Grand Tower Energy Center, LLC; and

6) The parties have agreed to the subject's land assessed values for tax years 2014 and 2015.[3]

DESCRIPTION

The subject property consists of a natural gas combined cycle gas turbine ("CCGT") power generation facility consisting of two 1x1 combined cycle units. The subject, Grand Tower, was originally constructed as a coal-fired power plant in the 1920's but was converted to a CCGT configuration in the 1950's and again in 2001, burning natural gas. The subject's two combustion turbines ("CTs"), unit one and unit two, are configured with two steam turbines from the existing coal facility, unit three and unit four, respectively. Features of the subject include the combustion turbines responsible for converting natural gas to electrical energy, steam turbine generators used for converting steam from the boiler to electrical energy, heat recovery steam generators ("HRSGs") which recover heat from the hot gas expelled from the combustion turbines and convert it to steam to power the steam turbine, along with various mechanical equipment, structures and foundations, piping, fire protection, tanks, transformers, substations, accessory electrical equipment, buildings and platforms along with controls and instrumentation. Based on an average of the summer and winter net capacities, the subject has a total net capacity of 503-megawatts. The subject is located on 336.32 acres or 14,650,099 square feet of land area on the eastern bank of the Mississippi River in Jackson County, Illinois, and competes in the Midcontinent Independent System Operator ("MISO") Illinois market.

OVERVIEW

The basic operation of a gas-fired power plant is as follows. A typical natural gas fired power plant receives natural gas via a pipeline which is then transported to the combustion turbine to

[3] PIN 46-13-300-001, which was not appealed in tax year 2014, will have stipulated land assessment of $633 in tax year 2015 only.

turn a turbine. The rotating combustion turbine is subsequently connected to a generator, which produces electrical energy. The exhaust is captured by the heat recovery steam generator ("HRSG"), used to convert the exhaust heat into steam. The high-pressure steam is then piped to a steam turbine, where it expands through the blades of the turbine, causing the turbine to spin. The steam is then condensed and the cooled water is sent via a closed loop back to the boiler to once again be heated. The rotating steam turbine is connected to a generator, which produces electrical energy which is moved to a transformer prior to entering the grid.

A typical natural gas–fired CCGT power plant is illustrated in Figure 1.

Figure 1: Typical Natural Gas-Fired CCGT Power Plant

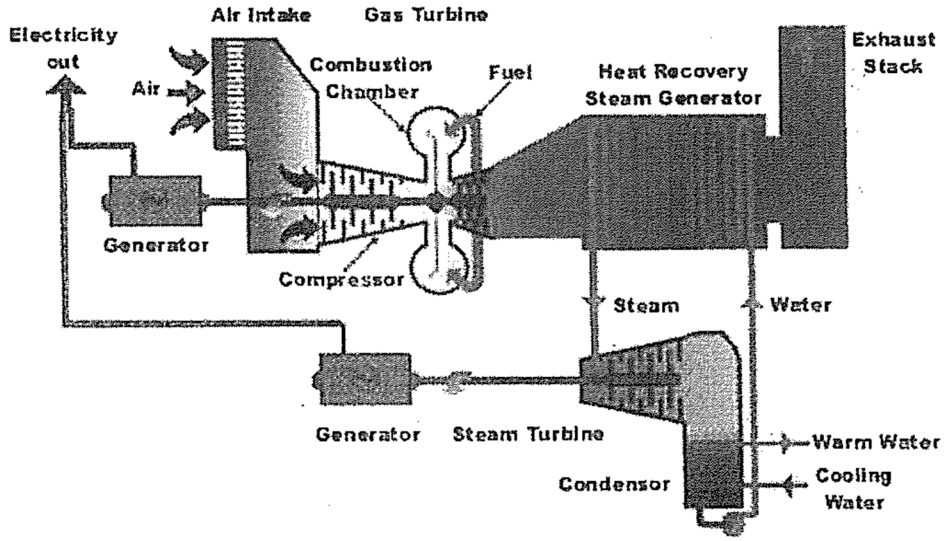

Image source: http://public.wsu.edu/~forda/Lcc.html

Figure 2: Transmission of Power

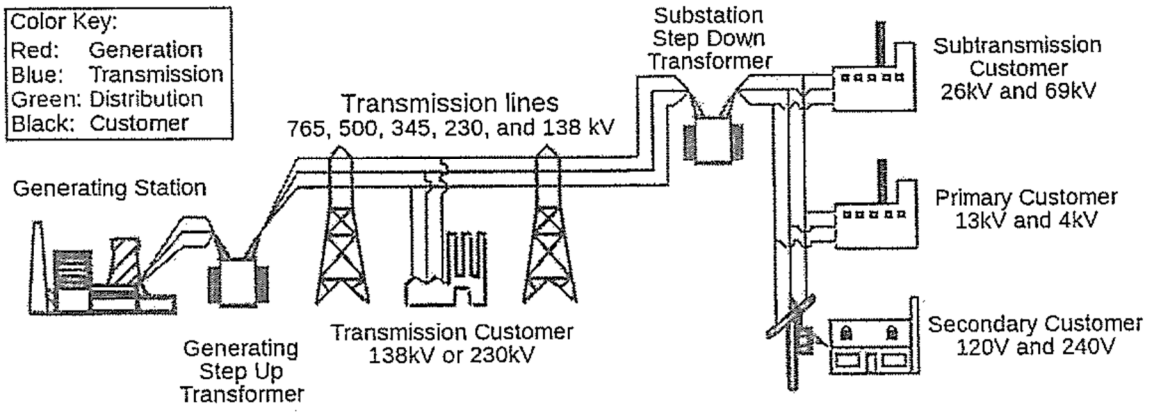

Image source: http://www.ferc.gov/industries/electric/indus-act/reliability/blackout/ch1-3.pdf

Once electrical power has been generated at a plant it is transported to the customer via the grid, or an interconnection of transmission lines. After being generated, electrical energy goes

through a step-up transformer, increasing its voltage so that it can be transported over large distances via high-voltage transmission lines. Some industrial customers receive power directly off these lines. After transmission, the electricity will go through a substation step-down transformer which lowers the voltage, so it can be used by the residential or commercial customer. Since electrical energy cannot be stored economically on a large scale, generation must fluctuate as demand fluctuates. If customers demand more or less energy at a given time, it is up to the power generators collectively to meet those needs.

The power generators are called upon or dispatched to produce electrical energy into the power grid from Independent System Operators ("ISO") and Regional Transmission Organizations ("RTO") which govern meeting the power demands throughout various regions of the country. The subject in this case is located in the Midcontinent Independent System Operator ("MISO"), a regulated power market.

Individual power plants participate in what is known as "day-ahead bidding." For example, it is estimated that a node, or region, will need a certain amount of energy at a particular hour the next day. The plants will then bid in at their marginal variable cost to generate the required amount of power, wherein the plant will ask to receive a price at which they can cover all the variable operating expenses incurred by running. Once all the bids have been received, the plants will be called upon to start up from least expensive to the point where the requested demand has been fulfilled. All plants will then receive the rate bid obtained by the most expensive plant that was called upon to run.

To fulfill the grid's demands, three categories of power plants are utilized: base load, intermediate and peaking. Base load plants are designed to operate 24 hours per day, seven days per week and are utilized to fulfill an area's constant power demands. Base load plants are more expensive to build but are generally more efficient to operate.[4] Intermediate or mid-merit plants are generally less expensive to build, less efficient and fill the gap between extremely low and extremely high-power demands. They can usually start up quickly and run for longer periods of time. Peaking plants are even less expensive to build initially, are generally even less efficient than the other types of plants and run only when energy demand is at its peak, usually during the hot part of the day in the summer months, to provide for any increased demand in electricity for a short period of time. In general, eco-friendly plants such as wind, solar and hydro plants come online first, followed by base load, intermediate load and then peaking plants.

ANALYSIS

The appellant, through counsel, appeared before the Property Tax Appeal Board contending overvaluation as the basis of the appeal. In support of this argument the appellant submitted a narrative appraisal prepared by Kevin S. Reilly, ASA, of evcValuation. Reilly estimated the subject property had a market value of $20,000,000 as of January 1, 2014.

[4] The Board recognizes wind, solar and hydro plants are generally considered base load plants with lower costs of construction and more efficient operation; but, for simplicity of explanation, only fuel consuming power plants are discussed in the overview.

The first witness called by appellant's counsel was Jonathan Beach, a principal of Rockland Capital. He is on the investment team for Rockland Capital and focuses on trying to find due diligence and execution on investments in the North American power and available energy space. Beach has two degrees from Rice University in mathematical economic analysis and a master's degree in chemistry. He authored five articles during his education. He has worked for Merrill Lynch in their analyst program. In 2006 he began his employment with Rockland Capital as an analyst. In 2010 he worked for a large Swiss investment manager looking at global infrastructure generally covering power and then in 2013 returned to Rockland Capital with a focus on U.S. power. He returned to Rockland Capital just as they had submitted an indicative offer to purchase a portfolio of three plants Ameren was selling with Grand Tower being one of the plants offered for sale. He was staffed to lead the due diligence process. Beach described an indicative offer as typically when power plants are being sold, an investment banker is hired to run an auction process which is done in two stages. In the first stage limited information is provided with a memo and some financial projections in which an indicative offer for the buyer to consider is prepared. However, it is understood full due diligence has not yet been conducted. With the indicative offer, it is judged who is to be invited in to perform full due diligence and provide a final binding offer. Beach testified that at the conclusion of his due diligence he considered Grand Tower was a little odd with it being a former coal plant where the steam turbines had been paired with new combustion turbines in 2001. Beach described the subject as a "Frankenstein" plant in the industry, which makes it a combined cycle natural gas plant, which typically operates at some reasonably high capacity factor, either base load or mid merit. But in this case, the market did not need very much power from Grand Tower, so it was operated as a peaking plant.

Beach described the three levels of power plants as being base load units which run most or all of the time, mid merit units that run half the time, and then peaking units that are really only running when there is an abnormal system condition or when there is high demand. Beach testified Grand Tower is run as a peaker plant because that is what the market bears. He further testified that the system operator operates a competitive market, and you tell the system operator what your costs are; if you will be profitable to run, the system operator is going to dispatch you and you will get the market price for power. Beach stated, however, that is rarely the case for Grand Tower.

When Beach returned to Rockland Capital in July 2013, he also evaluated the Elgin and Gibson City plants also being packaged together with Grand Tower. As part of his due diligence for Grand Tower, he tried to understand Grand Tower as the potential of a stand-alone business and not just one asset inside of a broader company. He was trying to look at its fixed costs structure, its variable cost structure, the condition and hiring consultants to opine on the specialty items. He was trying to understand the abnormal environmental or other liabilities associated with it. He was trying to get a separated view of the plant to see how much money it could make in the market it operates in over time.

Beach testified he found that Grand Tower had a lot of issues which were tied to Ameren neglecting the plant for many years. He further found the plant was past due on a lot of maintenance and had forced outage rates that were very, very high; with availability rates that were very low. Beach stated the plant's condition was generally bad with several environmental

liabilities that a new owner was going to have to deal with. The environmental liabilities were related to asbestos in the old coal plant that was retired in place. In addition, there is an ash pond connected to the time when the plant was an old coal fired facility, in which the new owner would have to remediate because of new regulations involving coal waste. In addition, Beach described a river intake structure that he stated would eventually have to be demolished. He also stated there was an old coal pile potentially needing remediation. He found these things a bit abnormal for a gas plant.

Beach described forced outage rates as referring to "e4d" which is an acronym for equivalent forced outage rate demand.[5] Beach stated this essentially means it is something that means that when the system wants your power or would want your power if you were available, that you are not there, not producing power. Beach testified that for 2013, Grand Tower averaged across all units a 58% forced outage rate, which means that about 58% of the time that the system operator wanted or would have wanted Grand Tower, it was not able to operate.

Beach stated Rockland Capital ended up buying the three facilities on September 30, 2013 in a portfolio package, which closed on January 31, 2014. Beach testified that power plants typically sell in an auction process, similar to the one in which the subject was purchased.

Beach then described the purchase of Grand Tower as Ameren hiring Barclays Bank, which was well known in the sector and a team from Lehman Brothers, one of the big advisers in the power industry. They then performed the two stage process he previously described and contacted a wide variety of potential bidders consisting of big public companies and small and large private investors. Ameren then provided limited information to gauge people's interest and to see how people were generally valuing facilities. Then all the people submitted first round offers or indicative offers, and from that group, Rockland Capital was one of the ones admitted to perform full due diligence and allowed to visit the site, meet plant management and Ameren management. Rockland Capital then received all sorts of records and things that were posted in a data room and they then spent several weeks going through all of the information to come up with a final binding offer to be submitted. Beach testified Rockland's final offer was for $143 million. After a few weeks of realizing they were not getting anywhere with Ameren they raised their offer by $20 million to $163 million. After that Barclays reengaged with them and they began trading a purchase agreement back and forth with Ameren. Beach testified that a day or two before the deal was ready to be signed, Barclays informed them another party had increased its previous offer above theirs and that they would have to further increase their offer, or they would stop the negotiations. They then agreed and met their demands and signed the purchase agreement shortly after that.

Beach stated that when evaluating Grand Tower, he did not use the sales prices of the other power generating facilities to determine what they should bid. He further testified that it was not relevant to any particular plant what some other plant might or might not earn. He explained that Grand Tower operates in a market where it can only get paid for what is in that market, and other plants operate in markets, where they get paid for what is paid in that market, and those can be widely different amounts.

[5] Counsel's closing argument reveals "e4d" is an acronym for what is referred to in the industry as "EFORD."

In order to not use sales prices of other power generating facilities to determine the bidding price, they used a discounted cash flow analysis. A discounted cash flow analysis tries to project how much money they think a plant might be able to earn based on the market and its operating characteristics. They are trying to predict its cost structure and understand its net cash flows over time and then discount those back at a discount rate to come up with a present value that they would then use for the purchase price. Beach testified that Grand Tower did significantly worse in 2014 and 2015 than what the projections indicated. Beach stated they ended up paying $168 million plus some adjustments for working capital for the three facilities. To his knowledge, Ameren was not forced to sell the properties. Beach further testified that the value for Grand Tower was an allocated value. The purchase agreement with Ameren states only a purchase price for the package of plants itself.

In order to come up with an allocated value, Ameren had three appraisals done for the three facilities. Beach testified that one appraisal had Grand Tower at a negative value. Beach testified that they used the three appraisals as a guide to determine the allocated value for Grand Tower. Beach stated one appraisal had a negative value, one had a minimal value and one had the highest value of $47 million, which was used as a basis. When Rockland Capital was bidding for the three facilities, they did not value all of the properties equally. Beach testified that Elgin was clearly more valuable than both Gibson City and Grand Tower combined, mainly because Elgin operates in a different grid. Grand Tower and Gibson City operate in MISO, while Elgin operates in a market called "PJM." In PJM there is a capacity market that goes on over a three to four year rolling period, so you always know every three to four years what the set stream of cash flows are and you know what you are going to receive with a very high confidence as opposed to MISO where it is between almost zero to one year looking forward. In addition, the historical values for capacity in MISO have been almost nothing. Beach testified that they knew there were many millions of dollars coming into Elgin over the first three to four years as opposed to Gibson City and Grand Tower where they had to just come up with their best estimate of what they thought the market might do.

Beach testified that capacity payments refer to when a power plant is running you are getting paid for the electricity you are producing, but a grid operator, including MISO and PJM, provides a payment just for a plant to be available if they are needed, which they are then required to turn on and be ready to run. Beach further testified that the broker informed them that he had an offer for just Gibson City and Elgin that exceeded their purchase price for all three facilities.

Beach then testified as to the steps taken to improve Grand Tower. They have tried to catch up on the past due maintenance to make it reliable and bring it up to speed to where it should be in the maintenance cycles on the steam turbines and the combustion turbines. They have also implemented some new procedures, recommissioned the duct firing in order to sell more capacity and potentially make more money. They reduced the start up time from eight to nine hours down to half that time to avoid the inefficient burning of gas without producing power. Beach testified that Grand Tower was not profitable in 2014 or 2015.

During cross-examination, Beach testified that duct firing somehow produces more capacity. He stated Rockland Capital does not actually operate Grand Tower, NAES is the third-party operator, and Rockland Capital acts as internal asset manager overseeing NAES. Beach further explained that the fixed costs on base load units are very high with variable costs lower than peaking or mid-merit units. He testified mid-merit units generally operate between 25% and 50% of the time with a peaking plant operating from 0% to 15% of the time. Beach stated the subject is selling power in an unregulated market through a bidding process a day ahead. He described a forced outage as bidding on a day ahead and then being unable to deliver when requested because of mechanical problems. He explained that they would then have to buy back the megawatts they were unable to produce at real-time prices. In regard to the subject's portfolio sale, Beach testified the other two plants were also in an unregulated market. Beach stated a peaking plant has the fastest start-up time and explained that eight to nine hours would be considered a mid-merit unit. Beach testified that a combined cycle plant could operate as a base load unit in the right market if it was operating enough. However, the prototypical base load units such as coal and nuclear plants have much longer start-up times, but they do not shut down for weeks or months. When Beach refers to a peaking plant, his description is based on a unit's capacity factor because the unit is only operating a very small percentage of the year because the market price is only high enough to justify its operation. But, technically, he stated you would not want to run a combined cycle plant as a peaking plant. Beach testified that in 2014 and 2015 the subject was running as a peaking plant. He said that in 2014 the subject was broken and not operational for a significant percentage of the time. Beach stated Ameren only operated the subject plant in the summer months. Since Rockland Capital purchased the subject, they have been trying to have a full year operation.

Robert Rapenske was next called as a witness. He is employed by Rockland Capital as a vice president in the asset management group. Rapenske manages multiple plants, oversees the daily operations, talks with plant managers, establish budgets and maintenance plans. He also participates in the due diligence process on potential acquisitions. Rapenske participated in the due diligence process for the purchase of the three properties from Ameren. He testified that the due diligence process for the subject's purchase was as Beach described earlier.

Rapenske's education came from the U.S. Navy Nuclear Power program. He was a reactor operator onboard the USS Kamehameha for four to five years. After that, for the next four years he worked on testing the Triton submarines. Rapenske explained that before crews could take control of the submarine, the crew would be sent to him and his staff for a six-week crash course on the prototype plant of high-power reactor physics, core construction, reactor protection and electronic courses. After the Navy, Rapenske went to work for Baltimore Gas and Electric at their Calvert Cliffs nuclear plant, units one and two. He preformed back to back refueling outages as an instrumentation technician. Then for six years he tried residential construction, general and commercial contracting. He then went to work in northern New Jersey for 16 years for a combined cycle facility as an instrument technician, maintenance manager, operations manager and plant manager. He then worked for NAES, the world's largest third-party operator of independent power plants in transitions as they acquired new facilities from different owners. He then returned to Rockland Capital at a coal and oil-fired plant in South Jersey. As part of the due diligence process on Grand Tower, Rapenske inspected the records of Grand Tower, then

after the purchase agreement was signed, he took a physical tour because it was going to become one of his facilities as an asset manager.

Rapenske testified that his inspection of the subject property concerned him because of the high forced outage rate and low capacity factor. He recalled the subject's capacity factor from 2001 to 2013 as being 8%, which is low for a combined cycle plant. Rapenske considered the subject a hybrid plant, which he testified was its downfall. He explained the subject was built in the 1920's with units 1 and 2 being coal-fired boilers. In the 1950's more coal-fired units were added. Those units were fueled by coal and created steam to run the two steam turbines and generators. These boilers were removed in the 1970's and the steam turbines were reutilized in the combined cycle configuration. Rapenske testified that it raises a red flag when a steam turbine, meant for a very slow start-up such as a very large coal boiler, is used for a fast start-up. He explained that theoretically, it works, but is not very efficient. He was concerned about the subject's long start-up time, forced outage rates and low capacity factor.

Rapenske later learned the subject plant runs out of water. Rapenske testified that during the first week after they bought Grand Tower, he remembers looking down at the river intake structure and seeing no water to run the plant as the intake structure was dry. He stated from 2001 through 2014, the subject was down 5,200 hours, either totally out of commission or had a reduced output because of the lack of water. Rapenske explained that as steam goes into a turbine, it needs to be condensed back into water and that water needs to go back into the heat recovery steam generator in the plant's current configuration. He explained that steam cannot be pumped per say without condensing it back into water which the Mississippi river does as it provides a cooling mechanism for the steam. Water from the river is directed into tubes which the steam crosses over to be condensed back into water which is returned as hot water back into the Mississippi river. He testified that without this cooling mechanism, there is no way to run the plant. Rapenske testified that this is not common in the industry and is not easily remedied.

A cooling tower, which a modern combined cycle plant would require, could be put in place, but that would add additional costs and most likely trigger replacement of the steam turbines as well, which he testified would be cost prohibitive. Rapenske also valued the other two plants involved in the subject's purchase. He explained they were simple cycle plants, easy to start-up, shut down, quick starting and were head and shoulders above Grand Tower. Rapenske was concerned with the maintenance at Grand Tower, particularly with the historical statistics and things of that nature with the steam turbine or steam turbine controls. He stated the steam turbine valves were a concern along with electrical issues with the plant.

Rapenske testified that each steam turbine has a generator associated with it that steps up the voltage before it goes out on the grid. They found the transformer leads that had high voltage insulation around them had deteriorated so badly that they were duct taped, which created a safety factor. They also found that several leads for the number 3 generator were no longer functional and actually de-rated that generator. He also found that because of lack of maintenance, the duct burners, which are 55-megawatts capacity, were completely inoperable.

Rapenske testified that the cooling water was a concern because when you run the plant with the river low and attempt to continue to run the plant, the intake screens are impacted by debris.

Rapenske stated the production superintendent's hands were tied by Ameren on what he was allowed to do as far as maintenance at Grand Tower. Rapenske explained "e4" as the equivalent forced outage rate or the amount of force outage hours a plant is forced offline or unavailable in comparison to the hours it is dispatched. Rapenske stated "e4d" is a more complex look at "e4." He explained that when dispatched, you do not always make money, some hours are actually negative. He stated "e4d" takes a look at the hours you are commercially in demand and are making money and how many of those hours you are forced off-line. He found there were months "e4d" was 100%. In 2013 "e4" was around 58% for the year, but, January through June of 2013, the "e4d" was approximately 65%. He testified that in 2001 through 2013 the long-term "e4d" was 18%, which he described was an abysmal number. That number is used to determine how much capacity payments a plant gets. It is a metric of availability when the market needs you. He explained that capacity revenue will go down as "e4d" goes up.

Rapenske testified that every plant greater than 20-megawatts across the United States reports the GADS statistics to the national organization called NERC. The plant supplies the GADS statistics, the raw data to MISO where it is calculated and reported to NERC. Rapenske stated they would love to see an "e4d" rating of 4% but would accept 7%. He stated that 7% is considered a high rating. An "e4d" rating of 50% is considered abysmal. At that point, it is called a spotlight, which requires further investigation to figure out what the issues are, and attempts needed to be made to pull them apart one at a time to figure out what to do with them. He stated they identified several of the issues up front.

Part of the issues were the personnel and the procedures they were using. They went through each maintenance task and found what was deferred and what was not. They looked at the electrical equipment, the electrical leads, the duct burners, intake screens, etc. Rapenske stated they could not continue to operate the plant in the condition it was in without receiving the same poor statistics. During the first two years, they had just scratched the surface and began to identify the issues.

Rapenske explained that every plant has an installed capacity rating known as "ICAP." The capacity you have for sale is basically "ICAP" times 1 minus your "e4d." If your "e4d" is 7%, you can sell 93% of you installed capacity, if the "ed4" is high, your capacity that is available for sale goes down. Rapenske testified that Grand Tower does not run continuously because it is a peaking facility and will never run continuously because it has a high heat rate, which is a measure of efficiency. He compared this as how many BTUs it takes to produce a kilowatt hour. He stated the subject has a high heat rate when compared to other combined cycle facilities. It is between a peaking facility and a combined cycle facility, which is not common in the industry. Rapenske testified that the desired start-up time for a peaking plant is 30 – 40 minutes and is just a simple cycle facility such as a combustion turbine. However, a combined cycle facility, such as the subject, at best has a start-up time of approximately 3 hours cold.

He stated they estimated $8 million to $9 million for the ash pond clean-up costs and $5 million to $6 million for the asbestos clean-up. He explained that the subject is started by starting the combustion turbine with natural gas. The combustion turbine compresses air which lights off hot air through a pinwheel, which is the turbine itself. The turbine drives the generator; and is considered a simple cycle facility. But in a combined cycle the exhaust heat coming from the

combustion turbine is reused and directed into the heat recovery steam generator, otherwise known as a boiler. This creates steam and is forwarded to the steam turbine.

He then explained that an hour into the start-up, you are trying to get the steam turbine online and its valves do not work, it doesn't start, and the entire start-up is aborted, and you are forced off-line. Then you are required to buy replacement power. He explained that there is no way to immediately fix the problem because it has to cool down for a day or two to get to the valves, and then send them out for repair. Rapenske testified the steam turbines of units 3 and 4 were the original ones installed in the 1950s. He explained the problem is the steam turbines do not have modern material, cannot start up quick nor respond as quick as a combustion turbine and heat recovery steam generator at the front end of the plant.

On cross examination, Rapenske testified Grand Tower does not have any value to Rockland Capital. It was only purchased because it was part of a better package that they thought they could resurrect. He explained Grand Tower is manned year-round but is not operated year-round. Rapenske stated the code "reserve shut down" means the plant is available, but the market did not need it. This has nothing to do with maintenance of the plant and is not indicative of a forced outage.

As for the ash pond, the subject is not receiving remediation variances from the Illinois EPA. He stated they have submitted a ground water management zone application and require more testing and more wells in accordance with Federal Regulations. Rapenske testified that there was no solid maintenance plan for Grand Tower at the time of purchase as they were trying to find people to operate the plant plus he was dealing with the other two plants also purchased at the time. Rapenske testified that when Rockland Capital took over the plant they did not address the operating procedures while he was there; however, they started looking at the maintenance procedures right away. He explained that during the first six months of a plant acquisition, it is geared towards getting internet connections and getting your personnel familiar with their new employer. They also had to converse with NAES and tried establishing a pattern, which performed their own audits on safety, environmental and maintenance issues.

Rapenske explained that a "hot gas path" is an inspection of the turbine section and combustion section of the hot gas pack of the combustion turbine. Rockland Capital did not complete a major hot gas path upgrade, renovation or replacement at Grand Tower in 2014; they did a combustion inspection, which had labor costs of approximately $250,000. After parts, Rapenske acknowledged the expenditure costs were $2 million to $3 million. Rapenske could not recall if Rockland Capital spent $12 million to upgrade the plant. Rapenske agreed the majority of problems were with start-ups.

In regard to the water intake, they have worked with the Army Corps of Engineers to dredge the river intake from the shoreline. Rapenske testified this was a short-term solution to an ongoing problem because of the buildup of sand. He stated every time it happens; the plant is out of operation for 10 to 14 days.

Rapenske reiterated that when they fired the facility, the duct burners were out of service and non-functional and had been for many years. They were not in service in 2014 or 2015,

however, they are currently in service. In regard to the subject's purchase, it was his understanding Grand Tower had to be taken as part of the entire three facility purchase. Rapenske testified that there were a multitude of things that caused the forced outages such as an exciter fault along with steam turbine control valves sticking shut or open. He stated, over time there were hundreds of them, with most of them being maintenance related. He stated it would have been the responsibility of the Ameren plant staff to inspect and determine which valves needed replacement along with inspection of the insulation on the generators. Rapenske admitted that during the due diligence stage, that would have been his responsibility. However, they are only given a day to inspect and he was busy with the other two plants. They did hire a third party to inspect the plant prior to purchase, from which a 3-page to 4-page report was generated, which identified asbestos, undersized gas turbine coolers, the ash pond, long start-up times and the duct burners.

The next witness called by appellant's counsel was appraiser Kevin S. Reilly, ASA. Reilly received his Bachelor of Science degree in mechanical engineering from Marquette University. He is the managing partner and owner of evcValuation, which is an independent appraisal firm focused on the valuation of energy properties, power plants, oil and gas pipelines, refineries, chemical plants and large complex industrial properties. In addition, they examine railroads and telecom. He has been in the appraisal industry for 16 years, starting at American Appraisal in 2001/2002. He is a senior accredited appraiser with the American Society of Appraisers and holds the ASA designation. He has served terms on the peer nominated and peer-elected machinery and technical specialties committee. He is licensed in Illinois and various states and has lectured on general appraisal theory methodologies, cost approach, economic obsolescence, functional obsolescence, various topics, all educational in nature at the ASA and various conferences. He has also published articles on various topics of valuation methodologies and techniques, including obsolescence, both functional and economic, and wrote an article on the valuation of co-generation facilities, which is power generation related. He has appraised numerous gas-fired power plants but has never appraised a plant with a configuration and make-up and model of Grand Tower. He has appraised approximately 40 to 50 gas-fired plants but has never seen or heard of a plant that is kind of a hybrid plant using a mix of old and new technology.

Reilly prepared a summary appraisal report for Grand Tower Energy Center, LLC, which was marked as Appellant's Exhibit No. 1 for identification. Reilly inspected the subject in August 2015 to meet with plant personnel and get a feel for the operation and layout of the facility. He generally starts with a paper tour while sitting down with plant managers and engineers at the facility. They then walk around the plant on paper to get an idea of what the major assets are, such as the turbines, HRSGs and intake. He then does a walking tour of the property with these same persons. The effective date of his report is January 1, 2014; however, based on his experience in MISO and the subject property, his opinion of value would not be significantly different as of January 1, 2015. Reilly testified the subject suffered from the same conditions of being a hybrid plant and market conditions that had not really changed from January 1, 2014 to January 1, 2015. He stated the capacity factor in 2014 and 2015 was approximately 2% or less, so the subject was continuing to operate as a peaking facility, actually below levels where a typical peaking facility would fall.

Reilly defined fair cash value as the amount for which a property can be sold in the due course of business and trade not under duress between a willing buyer and a willing seller. The property identified in his report is Grand Tower, located in Grand Tower, Jackson County, Illinois and the property rights he valued was under the fee simple premise. The area around Ground Tower was described as a mix of uses, with residential surrounded by agriculture farmland and two industrial properties. The subject site consists of 336 acres irregular in shape with 6,510 feet of frontage on the Mississippi River. Reilly described the subject as being at level grade and appears to have adequate drainage.

In describing the improvements, Reilly explained the subject is unique as it is a combined cycle gas turbine the way it is currently configured and is unique in the fact that it is a hybrid wherein it contains old technology from the 1950s combined with newer technology, which is still for its age, more modern technology, that was put in place in 2001. The newer assets are the combustion turbines and the heat recovery steam generator and then there were some support aspects that were upgraded as part of that configuration. The major old assets that remained in place were the 1950 vintage steam turbines and the condensing system. He stated the original plant was built in the 1920s with a lot of structures still in place from that time period. The original configuration of the plant was built as a coal-fired plant, which basically boils water to produce steam which is pumped or fed into the steam turbines.

Reilly described the plant as highly inefficient since it began as a coal-fired plant converted to a gas-fired plant because it has a high heat rate requiring long start-up times, approximately eight hours from a cold start, five hours from a hot start, which limits its ability to enter into the market as a peaking plant, which it is currently forced to operate in based on its operating characteristics. The long start-up hours make the subject miss a lot of the hours of the peak market which normal peaking plants can operate in. He stated peaking plants take anywhere from 20 to 30 minutes to start up from a cold start to a hot start and reach full load. He explained if they are called on to operate, in 30 minutes they are making money. He described the subject as a "penalized plant" for its current configuration.

He described a peaking plant as being used to capture peak moments in the market when demand for energy is high and can shut down when demand decreases, typically during overnight hours. Base load plants, like a nuclear facility, typically want to run all the time. They run 90% of the time and only come down to refuel or if there is a forced outage because of a problem. Reilly explained that coal plants are typically base load plants with operating expenses that are fairly low. He described the subject as an intermediary plant in its current configuration as a combined cycle gas turbine, somewhere between intermediary and base load. He stated the new super-efficient combined cycle plants run as base load facilities running 70% to 80% of the time. Older, less efficient combined cycle plants gas turbines run 40% to 60% of the time. Reilly testified the subject fits operationally as a peaking plant because of its limitations and its operating characteristics.

The subject contains four turbines, two of which are combustion turbines that were installed in 2001 and two of which are steam turbines installed in the 1950s. Reilly stated the records he received did not indicate if the steam turbines were ever rebuilt or brought up to modern standards. He stated that turbines, whether new or old, go through maintenance, inspections,

major maintenance turnarounds, and things of that nature. Reilly explained that the heat recovery steam generator ("HRSG"), which takes secondary exhaust from the combustion turbine, reheats it into a second form of steam, and feeds or supplies the steam into the steam turbine to produce energy was installed in 2001.

Support equipment would include the mechanical equipment such as the condensing system, pumps, motors, structure foundations, piping, fire protection, tanks, electrical equipment and general support equipment for the entire facility. The subject also contains land improvements, fencing, pavement, and controls and instrumentation allowing operation of the facility. Reilly testified that he did not value the subject's buildings separately from the rest of the facility. This is because in the sales comparison approach, they are included in the sales prices; they go with the property. In the income approach, the cash flows that are generated need the buildings to support the operation inherent in that approach. In the cost approach, the information used came from what the Energy Information Administration publishes through the Department of Energy which produces an Annual Energy Outlook, providing a cost to construct various types of technology, with gas-fired power plants being in that group. The data is produced on a dollar per kilowatt basis, and in that cost, the buildings are included.

Page 25 and 26 of his report (Appellant's Exhibit No. 1) describes his highest and best use analysis of the subject site. His conclusion was the subject plant's highest and best use was as its current use as a peaking gas-fired plant selling power to the Midcontinent Independent System Operator, MISO, market. In reference to the subject's expected physical life, found on page 66 of his report (Appellant's Exhibit No. 1), they performed a physical deterioration analysis as part of his cost approach analysis. He looked at the average service life for the assets and their life expectancies based on the first day they were put in service with normal maintenance and upkeep to the end of their normal, average, service life. This was based on experience, discussions with engineers and various publications he reviewed over the years. He then looked at the chronological ages, however, because of ownership changes, the records were not very good. They were unable to get a clean property record for the subject. Therefore, they had to rely on discussion and observations wherein they were able to quantify physical deterioration and ultimately at the end quantify the estimated remaining physical life of 18 years as shown on page 66 of his report labeled Physical Deterioration Analysis.

Reilly developed all three traditional approaches to value in his report, the sales comparison approach, cost approach and income approach to value. All three approaches were developed because the Uniform Standards of Professional Appraisal Practice ("USPAP") requires them to be considered to be able to correlate values from multiple methods. On page 36, of his report (Appellant's Exhibit No. 1), he discusses the subject's sales history. The subject's sale closed on January 31, 2014 but was announced in October with a signed agreement occurring in September 2013. Ameren was the seller and three properties were involved in the transaction. To his knowledge, the subject's purchase price of $47 million was allocated from the sale price of all three properties.

In the cost approach analysis Reilly estimated the subject's replacement cost new. He explained that the difference between replacement cost new and reproduction cost new is that reproduction cost new is developing an exact replica, a mirror image of the property that is there. It

oftentimes involves functional obsolescence due to excess capital costs. Reilly stated the true starting point of any cost approach really is the replacement cost new, and replacement cost new is the cost to build a modern facility of equal utility. He further stated that an investor looking to buy or develop a plant has two options based on the principle of substitution. They can either go out and buy an existing plant or they can build a brand new one. They are not building a mirror or exact replica of some other plant that exists in the world, they are building a new modern facility. There is a difference between the new modern plant and the subject that they could buy, which includes wear and tear, physical depreciation, functional issues and then economic and capital expenditures for regulatory purposes.

In his cost new analysis, he did not use a combined cycle facility, it was replaced with a peaking plant determined to be a combustion turbine facility. Utilizing the documentation published in the Annual Energy Outlook by the Federal Government, they looked at various forms of power generation technologies, combustion turbines being one of those, and they used that information on a dollar per kilowatt basis as a starting point. Reilly estimated the replacement cost new for the property of $388 million. From this he then allowed for a loss in value based on several components of depreciation. They examined physical deterioration, functional obsolescence, economic obsolescence, and then obsolescence due to necessary capital expenditures. (See page 64 – 66 of Appellant's Exhibit No. 1) Reilly concluded physical depreciation to be 50% based on an age-life relationship looking at the age of the assets and the average service life, expected life of those assets to come up with a ratio. Based on his experience, knowledge of the facility and discussions, they concluded an actual average physical deterioration which was capped at 65% except for the new major assets such as the combustion turbine and heat recovery steam generators. Reilly explained that the age-physical life ratio of the actual calculation for all other major equipment, the categories of equipment that were capped, all exceeded 100% because they were installed in the 1950s with some of the buildings built in the 1920s. He explained that they were assuming an operating plant that is going to remain operational with maintenance protocols put in; so, the assumption was made that it would be kept in good working condition.

Reilly testified that functional obsolescence was due to the excess operating expenses found on pages 67 – 70 of his report. (Appellant's Exhibit No. 1) In this analysis, they compared Grand Tower to a new modern replacement plant which is a combustion turbine facility. They looked at the fixed and variable operating expenses, including maintenance and labor. They also looked at the cost of fuel required for each facility. They calculated a negative $1.9 million in functional obsolescence. In examination of economic obsolescence, they calculated an earnings shortfall relying on the premise of an investor's decision to buy an existing plant or build a new plant. They assumed they were going to buy a brand-new plant, state of the art, no physical depreciation, no functional obsolescence. He explained the new plant would have certain operating expenses, a heat rate, a required quantity of fuel to burn to produce power. So, they ran a cash flow scenario for the new plant with no physical or functional obsolescence, however it may have economic obsolescence. They then present that cash flow back to a value today, and if its equal or greater than the cost to build the facility, there is no economic obsolescence. If it is less, then economic obsolescence exists. They calculated 94% economic obsolescence present in the subject, and then concluded 90% was appropriate.

They next examined necessary capital expenditures ("CAPEX"). He explained most power plants, regardless of their technology, are subject to regulatory mandates. The subject has an ash pond because it used to be a coal plant, which a brand-new plant would not have. The subject has once-through cooling, so it has 316(b) issues, which is a regulation that has been put in place to require retrofits, upgrades and maintenance expenses, cap expenses put into to comply with 316(b). They looked at the budget for expenses that if someone were to come in and buy Grand Tower, they would have to comply with or otherwise the facility would be fined or penalized, affecting its value. They pulled out the environmentally required CAPEX, not just the normal maintenance CAPEX. They excluded the maintenance CAPEX and only looked at the required environmental stuff as shown on page 74 of his report (Appellant's Exhibit No. 1). In his report, he discusses the ash pond remediation and 316(b) compliance, and they show the capital expenditure and then present a value of those ($9.9 million) as of the appraisal date as a penalty. Reilly testified, this does not mean $9.9 million would necessarily be expended in 2014 because he was projecting a budget of six years. His budget projection begins in 2014 and is projected through 2019. He explained that these expenses will be required to occur over the six-year period and is presented as a value back to January 1, 2014.

In summary, they show the cost approach summary on page 75 of his report (Appellant's Exhibit No. 1). They used the replacement cost new and then deducted all forms of depreciation. They started with $388 million, took out the physical deterioration of 50% which equated to $194 million and then added back the $1.9 million in functional obsolescence into the cost approach. They then deducted the 90% economic obsolescence which equated to $174,600,000 from which they subtracted out the curable economic obsolescence for the necessary capital expenditures of $9.9 million. This equated to a cost indicator of value for the improvements of $11.4 million. They then added back a land value of $2,388,000.[6] In his analysis, Reilly estimated a cost indicator value of $14 million.

In his income approach to value, Reilly developed two methods, a discount cash flow analysis and a direct capitalization method. Reilly testified the discounted cash flow is a projection of expected cash flows over a certain term, looking at revenue, cost of fuel, expenses, capital expenses, and basically get into the bottom line income number. He stated you can then present-value that income number using a discount rate to value as of a specific appraisal date. He testified that this is done for power generation plants because you are dealing with commodity prices and this is the most common method used to value plants in the income approach to value. This is what he has used with buyers and sellers in the past to develop purchase price decisions. He stated the financial community, private equity firms, investors are all using cash flows to come up with a value.

On page 38 of his appraisal report (Appellant' Exhibit No. 1) he goes through all of the various components he just discussed, revenue expenses, cost of fuel, capital expenditures and a discount rate development. The discounted cash flow analysis is found on page 56 of his report (Appellant's Exhibit No. 1). Looking at page 56 of his report, he explained row "4" with a "1" and "2014" depicts year one of 2014 and is depicting out ten years. Reilly testified that in the

[6] Reilly explained that the stipulated land assessment presented immediately prior to the hearing would have to be substituted into his calculations.

discounted cash flow analysis, they were not developing the discounted cash flow analysis based on just ten years, they basically calculate it into perpetuity. They only go out ten years because, in his opinion and he believes in the financial communities' opinion, anything beyond ten years on a commodity projection is speculative. He stated if you go out 15, 20 years, to project electricity and fuel prices 20 years into the future, no one is making any financial decisions that he as ever seen based on projections that go out beyond five years, but they use ten years because it gives a good sample of the expectations, but it does not get into speculation, it helps eliminate that.

He then capitalizes the tenth year in a normalized period, basically into perpetuity going forward. He stated they are not trying to come up with a value for the ten years cash flow plus that perpetuity calculation because they get added together. As shown on row "9", page 56 of his report, in the discounted cash flow analysis, it depicts the revenue section of the analysis. It depicts really two major forms of revenue for the subject which is the sale of electricity through power generation into the market, and then also the capacity payments. Row "12", page 56 of his report, depicts capacity payments.

On the revenue side, they looked at the actual energy price Grand Tower would receive in 2013 and then they looked at two forms of forward curves. A forward curve is the price differential, change year over year going forward. One curve is the Ventyx, which is a reputable third-party market projection provider that works with banks, financial lenders and institutions. He explained they are subscribed to by almost every major market in the country. He stated these are independent system operators. He used their information along with the Federal Government forward curves to come up with the direction in which the 2013 actual price was going to move going forward. He testified the capacity payments were based on marketer information. In MISO, most of the capacity is bilateral agreements whereas in PJM they use forward capacity auctions of three years, whereas MISO tends to be a year with a bilateral market for the contracts. He stated they have to rely on market information, which is the marketers, the buyers and sellers of capacity, were provided marketer information from AEP based on relationships to where the market was and where it was expected to go through 2019. He testified this was used to develop the pricing for capacity. Reilly testified that because MISO only goes a year out, the risk of investment in a property is increased as compared to PJM properties. The established price between the buyer of capacity and the seller of the capacity creates the risk. In regard to PJM, it is a public auction; the price is set three years into the future and it continually rolls three years into the future. So as of today, he knows three years into the future what capacity a plant is going to get paid for that plant in that market. If you go out to the next year, he is still going to know three years into the future what the plant is going to get, which helps mitigate risk, and that is why in his opinion, plants in PJM tend to be more valuable because it has a robust capacity market, it is doing pretty well, and you know what it is going to be. He testified, that is not the case in the MISO market.

Row "15, page 56 of his report depicts the calculations for cost of fuel. Because it is natural gas, they used Ventyx and the AEO forward curve for the price of gas. Rows "18 – 23" depict operating expenses needed to operate the plant, to be able to produce electricity to be sold into the market. He stated this information was all published through FERC, which is the Federal Energy Regulatory Commission. Public documents, called FERC Form 1 is used by Ameren to

report through FERC, so they had historical operating expenses, however, FERC Form 1, does not include the general and administrative expenses, so they added row "22" to show a small expense for general and administrative expenses of approximately $500,000 a year based on 10% of the total operating expenses. Reilly explained that row "30" in his analysis is the CAPEX or capital expenditure budget. He used the numbers for years 1 through 9, provided directly to them which was dated December 9, 2013. Year 10, because of spikes over time in the CAPEX budget, are a result of major projects, major maintenance, things of that nature. So in year 10, they tried to normalize the CAPEX expenditures looking at years 1 through 9 and years 2 through 9 which averaged right around $3 million, which was then taken into consideration as they were trying to capture a normalized level of inclusion of major expenses because of the spikes.

Reilly testified they accounted for residual value which is shown at the bottom of page 56 of his report under stabilized cash flow ($6,579,469) based on a four-year average looking at years 7, 8, 9 and 10, averaging the cash flow for that year. Again, they were trying to normalize the expected cash flows going into the foreseeable future, if not perpetuity. They then calculate a typical capitalization to come up with a value indication of $69 million, or $70 million, rounded, shown as stabilized free cash flow market value end of year 10. They then present-value that back to January 1, 2014 and add that to the sum of the cash flow for the first ten years to come up with a business enterprise value.

The result of the discounted cash flow analysis indicated a value of $20 million for the subject. As a check, they also prepared a direct capitalization approach to value as shown on pages "57 - 58" of his report. Basically, they looked at the same revenue and expenses, cost of fuel, operating expenses and capital expenditures, as used in the discounted cash flow analysis. They then tried to normalize them into a one-year normalized cash flow capitalized into perpetuity, which result indicated a value of $21 million.

Page "76" of his report depicts all three approaches to value were considered in his final reconciliation. However, recognizing that the subject is an income-producing property, and investors or potential purchaser of such property would primarily rely on development of an income approach analysis, the majority of weight was given to the income approach to value in the reconciliation and conclusion of fair cash value.

In regard to his development of a sales comparative analysis, Reilly testified that there are a good number of gas-fired power plants that sell, however the subject presented a challenge. He explained there are internal and external characteristics with any power plant. The internal characteristics are the operational characteristics, heat rate, capacity, the generation ability, the total generation or net generation, configuration, make and model. The external characteristics or factors also impact a plant. Those are the location, what market a plant is in and transmission constraints. Reilly testified he has seen two plants across the street from each other where one is constrained and other is not. The unconstrained plant can generate more cash flow. The strength of the market, supply and demand are drastically changing and because of this, a sales comparison approach to value is not all that meaningful as an indicator of value.

Reilly testified there is nothing in the market comparable to Grand Tower as it is configured. He stated Grand Tower has a high heat rate, is inefficient and has forced outage rates through the roof with long start-up times. He testified that is difficult to find comparable power plants and then be able to adjust them back to the subject, which created a lot of issues as far as the weight that was given this approach. Therefore, the sales comparison approach to value was given minimal weight in his analysis.

He began his sales comparison approach analysis by looking at plants that were operating with the same utility as the subject plant; operating as a peaking plant. He was looking for sales of combustion turbine facilities, ones operating in the same manner as a peaking plant similar to Grand Tower.

Reilly identified six sales as shown on page 35 of his report. They adjusted the comparables for operating capacity, age, market location, market conditions and time. With the adjustments, they tried to come up with a benchmark to compare within reason to the cost and income approaches to value. Reilly stated there were not a lot of sales within the MISO market. Reilly testified the indicated market value via the sales comparison approach to value for the subject $35,210,000. He stated they basically looked at the six sales and got each sale to an adjusted dollar per kilowatt basis based on the adjustments at the sales price with the adjustments. They then applied that to the net capacity of Grand Tower using 503-megawatts.

Reilly testified they used net capacity instead of gross capacity because net capacity is the sellable capacity that a plant can sell, it is how plants are really measured. Gross capacity, on the other hand, includes capacity that is called parasitic load which includes power to operate pumps, motors, lights and computers. He explained that this parasitic load is not sellable into the market. Because every station has a different parasitic load, net power is the best way to look at true comparability between plants. Reilly stated the EIA number in the cost approach reported by the Federal Government is where they get the dollars per kilowatt, which is reported on a net basis and in the income approach to value, you can only sell power in a net amount with the rest of the stuff being consumed, which cannot be sold.

Reilly testified his cost approach indicated a value of $14 million, his discounted cash flow analysis indicated a value of $20 million and his direct capitalization analysis indicated a value of $21 million with his sales comparison approach indicating a value of $35,210,000. Reilly again testified he gave the sales comparison approach to value minimal weight based on the unique characteristics of Grand Tower and the general challenges with the sales comparison approach. Reilly testified the cost approach to value generally tends to be a good indication of value on power generation plants; however, Grand Tower has unique operating design characteristics given that it is a hybrid plant, is old and has a lot of depreciation, which tends to make the cost approach to value a cost indicator that is less meaningful.

Reilly testified that buyers, sellers and investors in the market rely on the income approach to value. Reilly testified that as part of a due diligence team where they are looking at plants for potential buyers, they only look at the income approaches. He stated the income approaches are exactly unique and tailored to inherently address all the operating characteristic issues with Grand Tower; its heat rate, its variable operating expenses, its fixed operating expenses. Then it

is taking the market components and projecting them as a form of revenue such that the bottom line cash flow is what anyone buying this facility would be able to expect. This is the reason the income approaches to value were given primary weight. Reilly testified the indicated income approach value of $20 million included the value of all machinery and equipment present at the site.

Reilly stated that he formed his opinion of value in conformity with USPAP and the standards of professional conduct of the associations to which he belongs. Reilly testified he has no interest in the property and his fee was not in any way contingent upon his value estimate.

During cross examination, Reilly testified his calculation of the subject's 503-megawatt net capacity was based on an average of the summer and winter net capacities. Reilly stated he relied on information that was provided by Rockland Capital based on historical net capacities to arrive at 503-megawatts. Reilly then verified his calculations using intervenor's Exhibit No. 1, a document he received from Rockland Capital showing the gross and net capacities during the summer and winter months for units 1, 2, 3 and 4. Reilly admitted that he elected to not include duct firing (non-duct fire and firing out-of-service) in his net capacity calculations which would have indicated a net capacity of 531-megawatts. Reilly admitted that his report does not tell the reader that duct firing capacity was not included when calculating the subject's net capacity. Reilly stated that as of the appraisal date, the duct firing had not been operational and was out-of-service. Reilly agreed that a document (intervenor's Exhibit No. 2) provided to him from Rockland Capital indicated a capital expenditure of $250,000 for duct burner upgrades. Reilly admitted that he erred in his report by including an expense for duct burner upgrades when he calculated net capacities for the life of the plant with only non-duct firing capacity. Reilly stated they appraised the subject as it was operating as of the appraisal date and indicated the $250,000 was a rounding error in his analysis and probably should have been removed, however, it would not have changed his results. Reilly agreed that he also appraised the subject as of January 1, 2010 with an appraisal dated March 14, 2011. Reilly admitted that in 2010, he used a figure of 555-megawatts of installed capacity. Reilly also admitted that in his 2010 report, he used 555-megawatts of installed capacity in his income approach to value and to calculate a replacement cost new for the subject.[7]

Reilly admitted that using a 503-megawatt capacity as opposed to a 555-megawatt capacity leads to a lower value in the sales comparison approach to value. He agreed that if he used 555-megawatts, his energy revenue number, found on page 40 of his 2014 report would be higher, with all else being equal. Further, on page 63 his replacement cost new would be higher. Intervenor's Exhibit No. 4 (FERC Form 1, dated 2012) was handed to the witness and identified as a document found on page 42 of Reilly's report as a document upon which he relied in his appraisal report. Reilly agreed that the net generation data and heat rates reported by the utility in FERC Form 1 (Intervenor's Exhibit No. 4) were different than the net generation data and heat rates found in his 2014 appraisal report. The numbers as reported on FERC Form 1 were higher. Reilly admitted that the operating characteristics found on intervenor's Exhibit No. 1 depicted heat rates for the non-duct-fired design computes to 7,436, on average. Reilly explained that the

[7] Reilly's 2010 appraisal report was marked as intervenor's Exhibit No. 3 for the record, without objection. The document will not be used to consider valuation for the subject in this decision.

7,436 depicts a 1-B design full load heat rate which is an instantaneous measurement at full load. He testified that the heat rate he used was not designed full load, it was the actual heat rate the plant uses because there was eight hours of start-up which is extremely inefficient when burning a lot of gas without producing power. He called this number a theoretical heat rate. Reilly stated they calculated the fuel consumed and BTUs based on a five-year average by using information provided by Rockland Capital. Reilly explained that counsel's calculation of heat rate was different because he was using a measurement in million cubic feet, not BTUs. Reilly stated that he concluded a capacity factor of 5% throughout his report for the subject and explained that capacity factor is a result of the generation or a quick measure of how often a plant is run. It is a factor in the amount of energy sales or electricity sales into the market based on the generation. Reilly agreed he arrived at a 5% capacity factor for the subject by averaging the 2008 through 2013 numbers, which is a six-year average, however, the year 2012 was removed from the calculation. It was pointed out that Reilly went back 6 years for his average calculation, and this calculation included 2008 which was the lowest capacity factor over the six-year period. Reilly believed that in the second half of 2008, gas prices plummeted. Reilly agreed that in 2012 the subject's capacity factor was the highest over the six-year period; also, a time when gas prices were the lowest. Reilly testified that 2012 was an unusual year, with low gas prices, however, it was also one of the hottest summers on record over the months and in early July wherein they had peak demand in the market. He considered this an anomaly. He stated a buyer would not expect that to occur and be normal going forward, which is why he excluded 2012 in his analysis. The subject's 2012 capacity factor was the highest factor over the six-year period analyzed. Reilly did not believe that low gas prices were a direct correlation with the plant running more. Reilly agreed that in 2012 the subject was able to run when the market demanded it and ran at the highest capacity factor ever of 24.49. Reilly explained that there was a risk that fracking could be banned or regulations incurred on fracking. He stated that if fracking stops, gas prices are going to increase. In addition, exports could impact gas and that the commodity pricing of gas was uncertain. At or about January 1, 2014, gas prices were low, but things change. Reilly noted in his report on page 19 that fracking had increased in popularity and domestic production had increased significantly. He also agreed that environmental regulations made it harder for coal plants to become economic which squeezed gas prices and led to an increase in coal retirements, including the MISO market. Reilly admitted that his report depicts the 2012 operating data was considered an anomaly and not indicative of future operations and an average of 2008 through 2013 excluding 2012 was considered reasonable in determining a capacity factor to apply to the discounted cash flow analysis. However, he then admitted that even though the 2012 data was considered an anomaly and not indicative of future operations, in the end he used the 2012 data to calculate a five-year average heat rate. He found it appropriate to use the 2012 heat rate, but not to use the 2012 capacity factor because it was not being impacted by the factors that impacted the capacity factor, it was in line with the historical averages. Reilly admitted that the subject's 2012 heat rate was above average over 8,400. After going over various years to be averaged, Reilly admitted that the only way to arrive at a capacity factor that supports his conclusion is by excluding 2012.

In regard to the sales comparison approach to value, Reilly agreed that his report did not contain heat rate or capacity factor as a unit of comparison when analyzing the comparables. Reilly acknowledged that even though the subject is a combined cycle plant, each of his comparables were simple cycle combustion turbine plants and do not contain a steam turbine generator.

Reilly contributed the majority of value for the subject to the combustion turbine and the steam heat recovery system generator because they were newer. In fact, one-half of his replacement cost new in the replacement cost new analysis, was attributed to the steam turbine generator and the heat recovery system generator, however, none of his comparable sales contained these two electric generating assets. Reilly agreed that simple cycle plants, like the comparables he selected, are less efficient than a combined cycle plant, such as the subject. Reilly reiterated that based on the complexity of the subject property and the hybrid nature of the subject along with the operational characteristics, the subject could not be compared to anything else, which is why he believes the income approach is the only meaningful indicator of value. Reilly used the subject's net capacity in order to adjust for operating capacity and agreed that most electric systems peak load during the summer months and that the summer capacity rating is the most important in determining the value for capacity for both compensation and meeting reserve margin requirements. He agreed that if SNL, the subscription service from which he got his capacity data, used winter capacities, they would be higher numbers. Reilly testified that he estimated capacity payment prices based on discussions and exchanges with Grand Tower Energy Center, LLC and an independent energy marketer (AEP) just prior to the appraisal date. AEP is a power generator and a marketer that buys and sells capacity in the market. Reilly obtained the information he used in his report from Rockland Capital and used public documents to verify the reasonableness of the information provided. However, he did not reference the use of public documents in his report.

Reilly was then questioned and affirmed the calculations he used in his income approach analysis. Reilly testified that he calculated a replacement cost new value for the steam turbine generator and heat recovery steam generator by looking at data from National Energy Technological Laboratory, a third-party engineering firm study along with cost models based on information provided by Black & Veatch, a builder and designer of facilities similar to the subject. However, the data relied upon is not included in his report. Reilly testified that for this appraisal he was not provided with a fixed assets list. For the 2010 appraisal, he was provided with a fixed assets lists, but found it was not reliable to use in his analysis. Reilly testified that his estimate of value for the subject was as of January 1, 2014 and that he did not prepare an appraisal of the subject property as of January 1, 2015, however, based on the market evidence, his experience and the operating characteristics of the subject plant, he would not expect the value to change significantly.

Reilly testified that the subject is junk, "Frankenstein." He believed the only reason Rockland Capital owned the subject plant is because it was part of a portfolio transaction. Reilly stated a practical reason Rockland Capital could not sell the subject property is because of the market. He did not think anyone would come in and buy the subject with the amount of risk that is associated with the small amount of revenue on a stand-alone basis. Reilly agreed that his value for the subject in 2010 was $30 million and his market value for the subject in 2014 is $20 million and that in 2015, there would be little change in value. Reilly explained that capacities in any instant second might not be the same because it is based on ambient conditions which change based on temperature and pressures. Power plants basically are more efficient in colder weather than in warmer weather because of thermal dynamics. Nameplate capacity, which is almost never used in evaluating power generation plants is when a plant is designed, and someone placed a plate on the plant and stated it is going to have a nameplate capacity of 500-

megawatts. The second type of capacity is gross capacity which is the total amount of output a plant can produce. Generally, it may be close to nameplate capacity, but is rarely the same and most likely lower. Net capacity refers to sellable capacity into the market. He explained that a plant may have gross capacity of 100-megawatts and can produce 100-megawatts but may use 10-megawatts to turn on lights, run pumps, motors and control systems, which leaves 90-megawatts to sell. Reilly testified that based on his experience and knowledge of the market a buyer or investor trading on the open market will look at net capacity. They are interested in what they can receive as far as revenue from energy sales.

Regarding revenue, Reilly explained that net capacity is only a function of net revenue based on sales of electricity. Reilly testified he used 503-megawatts net capacity for the subject throughout his report, which was the average of the winter and summer months over a one-year period. As for 2012, Reilly testified that he excluded that year because he was trying to determine a normalized capacity factor that a buyer or seller should expect as a normal average going forward. However, 2012 was a period with low natural gas prices and all-time peaks as far as demand based on weather in July. He found 2012 was off the charts compared to the other years. Reilly stated that power plants are not always operating on a profit as there are times a plant can get a high capacity factor and be running at a loss if it stays on-line. If a plant has eight hours to ramp up and must run for five hours, there is a chance it will stay on-line to operate the next day, so they will stay online overnight probably operating at a loss. So basically, high capacity factor does not necessarily mean a plant is profitable. Reilly believes that had he included 2012, he would have overstated the actual capacity factor that a buyer could expect going forward. Reilly testified that the subject does not really fall into the category of a peaking plant but is forced to operate as a peaking plant based on its characteristics but is so expensive to operate and only comes on when the price is very high. The problem with the subject plant is that it takes eight hours to fire on as opposed to 20 to 30 minutes like the combustion turbines. The subject misses a lot of the peak hours where it just spikes for an hour or two and then drops back down. The subject misses all of that peak time and because of that cannot get on-line fast enough. The subject's long start-up time is more of a characteristic of a base load plant like a coal plant. The subject was not designed for quick starts. Reilly stated the subject cannot operate as an intermediate plant or base load plant. The reason it operates in the peaking percentage range is because it costs so much to start the plant. He explained that if he owns the plant, he has a cost that he is going to bid into the market on the day ahead basis. If the number is $50 per megawatt hour, then the market will start with all the base load plants, the low-cost nuclear, coal, wind and hydro plants. As demand starts increasing, the day gets hotter, air conditioning is coming on and demand is increasing, the peaking plants are called on-line because the energy price increased until it reached the point of $50. The challenge with Grand Tower is that it needs to know eight hours in advance because it cannot just flip the switch and be online in 20 minutes. So, in the day ahead market, if you know based on weather forecast and prior day's demand, MISO has a good idea of what plant is going to be called on to generate so they can say be prepared to fire up eight hours before they think they actually need you. Sometimes they fire up and are not needed. Sometimes the subject has problems with operation or being called on to operate and it goes to the forced outage rate because their steam turbine valves get stuck. He explained that it might fire up the combustion turbine, fire up the heat recovery steam generator and start sending steam to the steam turbine and it trips the plant off-line, which in that case, MISO has to call the next plant in line along that curve and then Grand

Tower is actually responsible for paying that price of energy back because they were expected to be there and were not.

Reilly explained that he did not include the duct fire capacity in his report and did not state this in his report because even though they were there from 2001 to 2014, they were out of service. Reilly stated that it would be improper to include the duct firing capacity in an appraisal report if they were not working. He stated there was no guarantee they would ever be working and would require a big leap of faith since they sat there for 14 years and were not being able to be used. He said that if they were working, it would have increased the CAPEX required to be spent and an increase in the gas expense because you must burn gas to fire the duct burners to produce the extra capacity. It might increase a plant's bid in price from $50 to $55, which may mean the plant would operate even less. He explained that a plant will fire up without the duct burners for the majority of the time, and if the energy price gets to a high level, assuming they are operational, they might fire on the duct burners for a couple hours.

Reilly testified that with power plants, there are two tests for utility. One is the production of megawatts and the other utility is generation. Reilly testified that he had to equate the cost approach to the value of Grand Tower. A person can buy Grand Tower or can build a brand-new plant. If that person is only going to run it at 5% or 2% of the time, no one in their right mind is building a combined cycle gas turbine if you are operating as a peaking plant, they would be building a combustion turbine. The second component of utility is that you have to categorize the plant as peaking, intermediate or base load and replace it with the proper technology within that categorization. That is the market, historical operations. Reilly opined all experts agree that the subject is a peaking plant based on its historical operation and its capabilities. If you create a combined cycle gas turbine, you are introducing super-adequacy and he is convinced that a peaking plant is the proper utility as using a combustion turbine.

Reilly stated the market for new gas-fired power plants as of January 1, 2014 was very uncertain. He opined that renewables were picking up a fair share of the capacity lost by coal plant retirements. He stated that if you were building a plant today it is most likely either renewable or gas, no one is building coal or solar. Reilly believed the subject would be worth more if it operated in a regulated market. He stated the subject's value is hurt by being in an unregulated market. Reilly testified that in his reconciliation he gave the cost approach slightly more weight than the sales comparison approach but pretty much minimal weight in his analysis. He stated the subject was a tough plant just based on the mixed type of assets, the hybrid nature of it. The subject contained 1950s vintage and 2001 vintage for the physical depreciation, which he stated was high. The market is weak so there is a lot of economic obsolescence. He felt the way they functionally applied it was the appropriate replacement. He was comparing a combined cycle gas turbine with a combustion turbine to get a positive and then add back the functional obsolescence. He stated it was complex. He stated the cost approach is an indicator of value and he thought it correlated well with the income approach for those reasons, however, he was not comfortable with the indication of value. Reilly testified that you could not have calculated the subject's value utilizing a regular income approach to value without a discounted cash flow analysis wherein they might have looked at market rates for gas prices as compared to the subject. Therefore, he thought the income approach on the subject in particular is the best indicator of value because there are so many unique operating characteristics like heat rate. He

needed to know the plant's heat rate to convert the gas into electrical energy and what can you sell it at. He stated you cannot go to the market rates like rental rates and things of that nature to get that information, it is not possible given the unique nature of the subject property. The income approach is good because you can use the variables of the specific plant to come up with the cash flows or expected cash flows. When asked if any discounted cash flow analysis inherently compounds one error over-and-over again since it is projected out over a ten-year period in this case to get to a present-day value, Reilly explained that was not the case in power generation. This is because the appraiser is developing the cash flows of commodity prices using a forward curve.

In regard to a question about the subject only operating 3-months out of the year, Reilly stated he was not surprised. He stated peaking plants only operate at periods of high demand. The highest demand in really any market was in the summer months when it is hot. He expected this plant to operate mostly in the summer months to get over the price hurdle. When asked why he excluded the $11 million CAPEX under his direct capitalization approach on page 57 of his report (Appellant's Exhibit No. 1), Reilly stated that on page 58 oaf his report his analysis shows that the challenge with the direct capitalization where you calculate in perpetuity, you have capital expenditures as a function of depreciation. Because you start spending CAPEX, you start to depreciate it. So, in direct capitalization on power generation facilities, generally what you do is you set the CAPEX number equal to the depreciation. His analysis depicts the capital expenditures and depreciation numbers offset each other. He had the expense of CAPEX and he then added back the depreciation benefit. This is because if you have CAPEX that is greater than depreciation, you super-charge the capital expense to a point where you are not fully depreciating the money you are spending. On the flip side, you cannot depreciate something more than what you have paid for it. Reilly testified that the $3 million that is shown on page 58 of his report is directly from the discounted cash flow on page 56 in year 10. This is the $3 million he testified to that he tried to normalize out over a longer time period, the average CAPEX year-over-year. Because there is peaks and valleys, some years you do not spend hardly anything, but then there are years you might spend $10 million for major maintenance. They were trying to average that out and just show that in direct capitalization.

During re-direct, Reilly testified the market for power plants were in a continued decline from 2008 up until 2014. Because of commodity prices, supply and demand, you cannot reasonably expect an appraisal done in 2010 to arrive at the same value in 2014. As the market was declining, so were the values. When asked if it was viable to keep the plant running to minimize the problems with the long start-up time, Reilly testified this could not be done because of the operating costs and the high heat rate, the efficiency is not there. The subject is not like a normal combined cycle plant that has a heat rate less than 7,000 BTUs per kilowatt hour. The subject is in the mid-8,000s, so the only profitability times for the subject to run are at high peak energies. If you keep it running overnight, it is losing money.

During re-cross examination, Reilly admitted that his method of deriving the subject operating expenses in his discounted cash flow analysis was to take the operating expenses of 2012 and increase them to 2014 (see page 42, Appellant's Exhibit No. 1). Reilly agreed that he took the 2012 historical operating expenses from FERC Form 1 and inflated them to January 1, 2014 and

then plugged them in to year 1 of his discounted cash flow and then inflated them every year thereafter at 2% throughout the course of his discounted cash flow.

At this point appellant's counsel rested its case in chief. The board of review then rested its case in chief based on the stipulations of the parties prior to the hearing.

Intervenor's counsel called Fernando Sosa, ASA as its first witness. The witness was presented with intervenor's Exhibit No. B, a rebuttal report of Kevin Reilly's appraisal report. Sosa testified that he prepared the rebuttal report in accordance with USPAP standards. Sosa has a Bachelor of Science degree in finance and has been an appraiser since 2000 or 18 years. He is an accredited senior appraiser with the American Society of Appraisers and a member of the Royal Institution of Chartered Surveyors, which is the European version of ASA or American Society of Associates. He has been appraising power generation stations since 2007 and has appraised over 100. Sosa is familiar with Reilly's appraisal report of Grand Tower. The scope of his work involved reviewing Kevin Reilly's appraisal report of Grand Tower and make a determination if it followed USPAP or if there were any inconsistencies in the methodology.

His principle observation of the Reilly appraisal report was that the reported $20 million value was not fair cash value, but more relative to salvage value. Sosa calculated the subject's installed capacity or nameplate capacity to be 570-megawatts. Sosa opined that it is appropriate to use a subject's installed capacity of a power plant when appraising a power plant. Sosa testified that power generation stations are specifically designed for their location and use. He stated when you design a 570-megawatt generation station, it is built and designed as a 570-megawatt power generation station, taking into consideration the parasitic load that the power generation station is going to have, loss of electricity due to environmental condition, whether it is ambient temperature, barometric pressure, elevation and loss of electricity through transmission. Once the electricity is generated, it goes to a step-up transformer which transfers the electricity to a substation. The substation puts the electricity into the transmission line and then it gets sold. However, during that process, you will have loss of energy as well. All of this is taken into consideration in addition to planned shut-downs, plant preventative maintenance, when designing a power generation station. Sosa testified that if you design a 570-megawatt power generation station, you will never produce 570-megawatts. Sosa stated you need to look at the EIA which publishes the capacity factor of installed capacity of what it would be running at in a perfect world. He explained that if a plant has a capacity factor of 90% to 95% means that it will only produce 90% to 95% of the installed capacity taking into account the consideration of the losses. Sosa testified that Reilly erred in using 503-magawatts as a starting point in his cost approach to value for replacement cost new because you then have to take into consideration that there is going to be parasitic loss. You have to consider loss of electricity due to transmission, ambient environmental conditions. Which means that it is not really 503-megawatts but would be only 80% to 85% of the 503-megawatts, which is lower than what its net generation capacity really is.

Sosa further testified that Reilly erred in in his cost and market value report by using a simple cycle combustion turbine rather than a combined cycle turbine because they are two different technologies with the only commonality being the use of natural gas as a fuel source. He stated the biggest difference between a combined cycle versus a combustion cycle turbine is the level

of efficiency. He stated a combustion turbine has a lower heat rate and has a higher capacity factor, generally speaking than a combined cycle turbine would. He stated the cost of a combustion turbine is more, but the cost reflects the efficiency. Also, the combined cycle has the heat recovery steam generator installed which allows the power generation station to be more efficient by recapturing that heat and recycling it to the plant an generating more electricity with less fuel. Sosa explained that Reilly erred in using a combustion turbine in his replacement cost new because it was a different technology than the subject, with different costs, different heat rates and different capacity factors. He also erred in applying a nameplate capacity or net generating capacity of 85-megawatts compared to a net generating capacity of 503-megawatts. Sosa stated it would have been better to use 570-megawatts of installed capacity. He stated this caused a discrepancy with the overnight costs, the heat rate and overall capacity factors that the two different technologies provide. Sosa opined that an 85-megawatt simple cycle combustion turbine plant does not provide equal utility as a 570-megawatt natural gas combined cycle plant. Sosa reiterated that a simple cycle combustion turbine has a lower general capacity factor. For example, a 570-megawatt installed capacity simple cycle, the overall capacity factor running at 24 hours a day, 7 days a week is going to be maybe 80% because it is inefficient as opposed to a combined cycle which runs higher because it is more efficient.

In regard to physical deterioration as estimated by Reilly, Sosa testified that Reilly's report would render the subject worthless. He testified that for a power generation station installed in the 1920s, it would have had a lot of refurbishments over the years at some point in time, and with each upgrade, you add life back into the equipment, thus making it more valuable. Looking at the steam turbine generators which were placed in service in 1951, he stated a steam turbine generator has to undergo a lot of maintenance. It is a very high-powered piece of machine that rotates at very high RPMs and has to be in shape mechanically. Borescopes have to be done, they have to look at the gear shaft to make sure it is not bending or pitting within the gears and that the fan blades themselves are operating. He stated that all power stations have extra parts to replace the fan blades and gears throughout the life of the generator. So to have a steam turbine generator to have been installed and operating since 1951 and not had a fan blade repaired or replaced, not had a borescope, not checked for pitting of the gears, not checked for bending in the gear shaft is impossible. Sosa testified that the normal useful life of mechanical equipment can range dramatically, however, Reilly made the assumption the original placed-in-service of the mechanical equipment was 1969. Mechanical equipment would be the breakers, main distribution panel, switchboards, switch gears, which would probably have been replaced when the subject switched over from its conversion from coal to natural gas. He stated it is not a situation where you are going to take out the boilers from the coal-fired power plant and put in gas combustion turbines and a heat recovery steam generator, there is more to it than that. Sosa said structures and foundations can last indefinitely and have a normal useful life by making betterments, doing maintenance, rehabbing and rebuilding. He believed most were made of brick and had been treated periodically throughout the years, so there should have been a change in the effective age, which he did not see. He said the piping installed in 1951 for a coal-fired power plant and not a natural gas-fired power plant, and it is highly unlikely that it is the same piping because you are now using piping from one technology to another. He testified that it was highly improbable that the two were going to match and so improbable that Reilly stated the subject was a "Frankenstein." Sosa agreed with the subject being described as a "Frankenstein" because you cannot use the parts interchangeably, there should have been an adjustment for

piping. He thought the transformers, which can last 40 to 50 years with maintenance, likely were replaced, refurbished, rebuilt or rehabbed at the time of conversion because of the technology switch from coal to natural gas. Because of the conversion from coal to natural gas, Sosa stated they would have had to request a new power generation license from FERC because of the change in technology and the fire protection system would have had to have been updated.

In regard to the tanks, which have a normal useful life of 25 years are emptied, stripped with new liners put in place, new plastic epoxy coatings are put in, new gravel base and then the tank has a brand-new life. He stated it was error to say the tanks are still operating in a normal useful life from 1951. Sosa testified that he has seen pictures of the subject and based on that opined that there had to have been some maintenance updates as the power plant looks immaculate, someone was taking care of it. He said it was improper to use an adjusted placed-in-service date of 1951 for the land improvements. He did not see how Reilly could use the start date for physical depreciation of 1951 for the land improvements; clearly the parking lots for the power station would have been repaved. Based on Reilly's report his controls and instrumentation with an adjusted year of 1969 means the same controls and instrumentation from the coal-fired plant were also used for the natural gas fired plant, a different technology. He did not think this was possible. Sosa testified that $170 million was spent in 2001 to convert the subject power plant from coal to natural gas and it is almost as though the $170 million has been completely removed from any part of Reilly's analysis, any part of the calculations of physical deterioration and has any variable input to the physical deterioration, functional obsolescence penalties, betterments, economic obsolescence penalties. He described them as being completely disavowed, but, in reality there was $170 million that was spent specifically to convert the subject from coal to natural gas, to a combined cycle generation turbine specifically. He thought those costs should have been taken into serious consideration because you now have a replacement cost new of that section and the fact that you are mixing new technology with old technology also has to be taken into consideration.

Sosa did not agree the Reilly's calculation of the functional obsolescence penalty. He found the functional obsolescence penalty was not calculated. He stated there was a $1.9 million credit, which he did not agree with. He described functional obsolescence penalty as a penalty within the equipment because it is not operating as it was designed to operate. It does not mean there is anything wrong specifically, it just means it is not operating the way it was designed to operate. Sosa stated that when looking at the Grand Tower power generation station, it is designed as a 570-megawatt combustion gas turbine, period. However, it is not operating as a 570-megawatt combustion turbine because there are inefficiencies; so there should have been an obsolescence penalty, but there was not. He did not agree with how Reilly calculated economic obsolescence. He stated Marshall & Swift, which is a valuation guide that virtually every single appraiser has seen at least once in their career has a section called salvage value. He stated the salvage value for power generation station is 10% of the replacement cost new. So, the 90% value of economic obsolescence that Reilly used indicated to him that the subject was worthless, that it is incapable of generating electricity, that it does not work. Sosa opined that the $11.4 million concluded valued under the cost approach, excluding the land, as equal to salvage or scrap value was a little low given the amount of copper wires, steel, aluminum, ferrous and non-ferrous metals within the generation facility. He stated the $11.4 million would probably be a little lower than scrap.

Sosa did not think Reilly's cost approach to value analysis was in compliance with USPAP standards. He opined that there were a lot of situations with the overall cost approach that were USPAP violations. He testified that Standards Rule 7.1, in developing a machinery and equipment appraisal, an appraiser must be aware of, understand, and correctly employ those recognized methods and techniques that are necessary to produce a credible appraisal. With the application of the cost approach and starting with a replacement cost new utilizing a combustion turbine as your source to calculate the replacement cost new as the first wrong step Reilly took. Not identifying the functional obsolescence penalties with the power generating station would the second critical error with the third critical error being the calculation of the economic obsolescence penalty by applying a 90% penalty on a power plant that is currently producing electricity.

In regard to Reilly's sales comparison approach analysis, he stated that Reilly reported that he utilized SNL as one of his sources for various different types of inputs. However, one of the things SNL could have produced would have been sales comparable to the subject. He said Reilly erred in comparing simple cycle combustion turbine to a combined cycle gas turbine, which is not an accurate comparison because the combustion turbine is designed with a higher heat rate and is specifically designed with a lower capacity factor. He stated the only commonality was the fuel source. He stated Reilly could have adjusted to the capacity factor of the combined cycle generation turbines, he could have adjusted the dollar per kilowatt downward. In addition, Reilly could have adjusted for the turbine itself because the turbine, the steam turbine for a combustion cycle gas turbine is different than that of the steam turbine that that is currently in place. He stated Reilly was able to allocate the overall value to each major component, one of those being the steam turbine, so he could have applied that same level of allocation to his comparables and adjusted them downward accordingly. If Reilly had done so, it would have resulted in a more reliable indication of value under the sales comparison approach. Sosa also criticized Reilly's use of 2007 and 2008 comparable sales for a valuation date of 2014. He stated that 2007 and 2008 sales were when natural gas prices spiked and there were not much of a demand for those power stations. He stated that there were more sales that were available that Reilly could have used, but for whatever reason Reilly chose to rely on 2007 and 2008 sales. Sosa felt Reilly's use of an effective age of 18 years in his sales comparison approach was not an accurate effective age of the power generation station and was penalizing the subject when adjusting the comparables.

Sosa stated that in 2014, the EPA passed the Clean Air Act which decreased the emission levels that coal-fired power plants could release into the atmosphere which basically buried all coal-fired power plants. He stated base load plants were critical in any country as part of the power generation infrastructure because they operate 24 hours a day, 7 days a week, 365 days a year. He said they have planned outages, so everybody is aware. Coal was the predominant power generation system used as base load in the United States. With the passing of the Clean Air Act, it was shutting down coal and a very large percentage of the base load facilities in this country and the only thing left was nuclear. What you have left is nuclear, natural gas and renewable energy to pick from to generate electricity. So, with the removal of coal, the only other technology available to replace coal as a base load is natural gas. He testified that if you look at large utilities such as NextEra, NRG, they are taking their coal fleet and converting them to

natural gas and operating them as base load facilities. This is providing they operate 24 hours a day, 7 days a week, 365 days a year as base load facilities with capacity factors in the double digits that can operate at factors upwards of 80% at a minimum of that installed capacity. This is as opposed to renewable energy such as wind turbines which are operating at a best-case scenario of 20% and solar which operates at less than 20%. He stated these power generating sources only operate during the day and an adequate storage for the energy has yet to be put in place. He stated renewable energy is not taking business away from natural gas. He stated right now renewable energy is going through their own little set of crises because the cost of natural gas and fracking, long-term power purchase agreements in the wind industry are getting cheaper and cheaper to the point where it is almost no longer economically feasible for the renewable energy plants to be able to produce electricity at those power purchase agreement rates.

Sosa agreed that it was appropriate for Reilly to not give the sale of subject property from Ameren to Rockland Capital no weight in the analysis because it was a portfolio sale and the overall conditions of the sale was unknown. In addition, less weight is being given Grand Tower when Grand Tower has a better capacity factor and a lower heat rate than Elgin and Gibson City. He opined that more weight should be given to Grand Tower. Sosa did not agree with Reilly's technique to arrive at a 5% capacity factor in the income approach to value. Sosa thought it should have been closer to 10% because of the amount of money and capital expenditures that were reported to Reilly, there should have been efficiencies to the plant meaning less fuel cost and an increase in the capacity factor which would adjust their revenue upward. Sosa stated that looking on page 39 of Reilly's report depicts the historical operational data table with specific inputs from 2008 to 2013. He said those inputs include the capacity factor, the outage rate, the heat rate and the net generation of megawatt hours. So, when looking at the capacity factors, it depicts 1.63%, 1.73% and then 24.49%. He stated that Reilly determined the 24.49% was an anomaly so he did not include that in his calculation of a capacity factor. However, the 8,700 BTU per kilowatt hour was reasonable for him to calculate the BTU, the heat rate in his discounted cash flow analysis. Sosa testified that it was error to pick and choose which inputs he wanted to use, either he should have chosen the 24.49% capacity factor in the calculation of the overall capacity factor as well as using the 8,700-heat rate or do not use it at all. Instead, he found Reilly did not use the 24.49%, but rather used the 1.63% and 1.73% capacity factor, which brings it to a 5%. If he would have just used an average, he would have come up to approximately 9.5% which would have affected the revenue stream in his discounted cash flow analysis model, thus compounding it ten years to the future. Sosa opined that Reilly inappropriately did not use the 2012 capacity factor of 24.9% because it was an anomaly then say the heat rate of 8,700 was fine along with the operating expenses. Sosa found no logic in Reilly's application of the particular inputs he used.

Sosa testified that since the subject is a "Frankenstein" pieced together which does not work well, does not work as designed with steam turbines from the 1920s and 1950s that are working the way they are supposed to be working with 90% economic obsolescence because of how bad the subject power plant is, as a buyer he would not spend $11 million in the first year to fix junk. Again, if the plant were junk or worthless, it would not be producing electricity. Sosa testified that in his opinion Reilly's appraisal report is not credible or reliable as there are too many inconsistencies.

During cross-examination, Sosa testified that his specialty was in machinery and equipment and that he does not have an appraisal license because he is not required to have one in the United States of America, including Illinois. Sosa stated that Steven Munson, an associate, assisted him in the income approach section. He agreed that the subject property is not the most cost-effective way of producing electricity at it currently stands. He agreed the subject was a "Frankenstein" because they were taking two different technologies and were trying to put them together by removing components and replacing components and were not going to receive the same efficiency that you would have received had it been a 100% installed combined cycle gas turbine. Sosa agreed that if the steam turbines are out of order, the plant cannot generate electricity. Sosa testified that a simple cycle facility cannot be more efficient that a hybrid like the subject because of the general design and technology of a simple cycle which is missing a key component, the heat recovery steam generator. Sosa said the if the steam turbines are out, the plant would not be operating at all and no benefits or economic advantage of having the heat recovery steam generator to the owner would be had. Sosa testified that a coal-fired base load plant can take 24 to 48 hours to start up. Further, gas-fired power plants predominantly have been used as peaking plants and intermediate plants because of their quick start-up, but, they can be operated as a base load plant. A gas-fired power plant, depending on its vintage can have a start up time of 30/45 minutes to 3 hours. Sosa would consider it to be inefficient to have an 8- or 9-hour start-up time as a peaking plant, and as such, he would not operate it as such. Sosa testified that both he and Reilly agree that the subject is more of an intermediate plant because as a peaking plant there is a very limited window to start generating electricity and transmitting it to the grid. Eight or nine ours means you are going to miss that window, which is reflected in the capacity.

Sosa explained that overnight costs are used in the industry across all technologies and is included interest expense during construction in the calculation of the replacement cost new. The overnight cost is what everybody in the industry uses to try to estimate what it will cost to build a power plant. Sosa stated Reilly considered overnight cost in his 2014 appraisal but did not call them overnight cost. Sosa stated Reilly got the information from Energy Information Administration ("EIA"), the same source that everybody uses to get their overnight cost. EIA publishes the overnight cost, estimated capacity factor and heat rate for every single year of every single technology in the United States. Sosa admitted that his original years in place assumed that all maintenance had been done, however, he did not know if it had been done, but assumed it based on the plant still being there, generating electricity.

Sosa agreed that if the generator leads were duct taped, that would not indicate that proper maintenance had been done. Sosa reiterated that it was improper for Reilly to use operating capacity of 503-megawatts in his report, when he should have used 570-megawatts of installed capacity as it was designed to do. Sosa testified that taking into consideration the parasitic loads internal within the power plant and loss of electricity, which would bring it down to a net generation of 503. But it was error to use the 503-megawatts as a starting point in calculating the reproduction or replacement cost new and use of 503-megawatts as the starting point in the sales comparison approach and in the income approach, which you then have to take the 503-megawattws number and reduce it because the 503-megawatts would then be the nameplate capacity and you would have to take out parasitic loss because of the environmental ambient temperatures, loss of electricity due to transmission. He stated the 503-megawatts would be

further reduced. Sosa stated it is only proper to compare the subject property to other combined cycle plants. Sosa stated there were other combined cycle turbines available to be used as a comparison closer to the subject age that were used by appraiser Lagassa, but not Reilly. Sosa testified that he has performed a hundred appraisals of power generation facilities, however, he does not provide values on land or real estate, only machinery and equipment, which he agreed is appraised differently than the fee simple interest of real estate.

The next witness called by intervenor Shawnee School District was David Wells. Wells has lived in Murphysboro since 1990. Prior to that, Wells lived in Grand Tower, Illinois. He is presently retired and has been for two years since May 1, 2016. Wells testified that he spent his 39-year career working full time at the power plant in Grand Tower. He was hired at Grand Tower on April 12, 1977 at the age of 19. He has graduated from high school and received two years of technical training at Southern Illinois University in building construction. His father and grandfather worked at Grand Tower starting in the mid-1950s through the early 1990s. He started his employment at Grand Tower as a utility man; a union starting position in maintenance. Grand Tower had different sections or classifications of employment. They had the maintenance section, coal yard section, an operation section and then an electrical section. Wells worked in all sections, excluding the electrical section, however, he aided the electrical section from time to time. He started out as a utility man working in maintenance and then progressed to the coal yard which had approximately six different sections. He then transgressed into relief operations and held the condenser pit pump man position for about seven years on unit 3. He has worked as an assistant turbine operator, assistant boiler operator on 3, boiler operator on 4 and worked as a turbine operator. He worked on all jobs but those are the jobs that he held. He bid certain jobs based on seniority. He worked as a turbine operator on No. 3 and No. 4 where they have a turbine operator and an assistant turbine operator. He has also held the position of relief man. His last position at Grand Tower was relief man for the control operator. There was only one day where he actually relieved, on Fridays.

As a control operator, they would bring the units on, take them off and watch them. During his career at Grand Tower, he became very familiar with the plant, its maintenance procedures, its start-up procedures and its operations. When he started at Grand Tower the steam turbines 3 and 4 were in operation and remain in operation today. He stated there were originally four steam turbines in the plant, however, steam turbines 1 and 2 were demolished, taken out of commission and removed. In 2001 Grand tower was converted to gas which took place over a two-year period. The conversion involved a lot of different contractors and different trades. Grand Tower also hired an architect and an engineer.

Wells believes the subject plant came online and went commercial in the late summer of 2001. He stated there was a commissioning process of the plant when it was repowered in 2001. During the commissioning process they brought in people that were familiar with the equipment and they had equipment training classes. Wells went to Florida for a week and was trained on the type of plant the subject consisted of. The guys came in an worked with them to get the units on and helped them with the equipment so they all learned together. Wells stated he knew the old part of the plant but was not familiar with the new part of the plant. The personnel that came in knew the new part of the plant, but, did not know the old part of plant. Together they worked to tune it, tune the valves and got the plant on and got it commercial. The group of personnel

that came in, the commission agents, were there for a year or more. The commissioning agents were out of St. Louis and from different parts of the country. They had a person that was really good with electronics and some were more proficient in the operations. Westinghouse also had a group there that did the tuning of the valves. Wells described them as a pretty big group. Also, during the conversion process, he worked with someone called the results engineer. The results engineer was kind of the overall engineer at the plant and oversaw the installation of new equipment and was involved in the repowering process.

Wells testified that the budget for the conversion process was just under $200 million for the cost of construction, however the actual cost of construction for the conversion process was almost $300 million. Based on his 39-year career at the facility, he would not characterize the subject plant as generally being in a deteriorated state. As he was approaching the time of his retirement in 2016 he would characterize the post-conversion working condition of the subject plant as good. Wells testified that a lot of the things had been rebuilt, cleaned up. The whole plant had been cleaned up and worked on, there was not hardly anything that was not touched. In 2001, they had brand-new equipment.

Wells stated that post-2001, the plant did not have a lot of electrical issues. He had never seen duct taped electrical leads anywhere in the plant. If he had seen duct taped leads, he would have turned it into the safety crew under the safety protocol procedures, which would have been fixed immediately. If there were in fact duct taped electrical leads, he would have had occasion to see them in his capacity as operating engineer. Wells testified that post-conversion, the subject plant was designed to run as a base load plant. During his employment at Grand Tower, the coal pile was removed, in fact Wells mowed it because it then consisted of sand and grass. Wells stated the coal pile was removed before they started the repowering, they burned all of it off and got down into the dirt and tried to burn some dirt in the end, running the old units, the old steam boilers. Wells stated it was fair to say that all the coal was removed from the coal pile, which occurred prior to the completion of the repowering in 2001. Wells testified that in the early 1980s, late 1970s he did hear complaints about asbestos hazards at the plant, however, after the conversion of the plant in 2001, he did not hear any complaints. Wells stated that in his capacity as operating engineer, he would have expected to have heard any complaints, if any. Wells testified that the river intake structure is where the circulators draw in water from the river and pump it to the condenser for cooling of the steam, for the water recycling process. He stated the water will end up in the condenser but is a different type of condensate and demineralized feed water. Wells further testified that during his employment as Grand Tower he was not aware of any complaints that the river structure intake needed to be completely removed and rebuilt. He believes that if that were the case, he would have heard of it.

Wells stated that they only had two maintenance men, and for any new project at the plant, whenever they were going to bring in contractors they would contact the union because they knew the two maintenance men could not handle certain projects, so they would look to sub out the work, they would have contacted the union for sure. Wells stated that new screens were installed in the water intake system at Grand Tower. The screens operate slowly and keep all the sticks and leaves out of the circulator pumps pumping water to the condenser. Wells stated the traveling screens are one of the most important parts of the intake. He said the intake structure can be maintained with simple dredging, and from 1977 through the date of his retirement had

been dredged two times. The dredging process involves using an extendahoe and the digging of canals to get the water to the intakes. Wells agreed that sometimes the subject plant runs out of water due to the intake system. He stated the intakes were dredged, so they did not actually run out of water, it just needed to be dredged. Over the course of his career, he has never observed or heard of an occasion when the plant ran out of water because of a lack of dredging. Wells would not agree with the statement that from 2001 through 2014 that the plant was down for approximately 5,200 hours because of a lack of water, it was never down for a lack of water.

Wells testified that from 2001 when the plant was repowered through 2014, he estimated that Grand Tower was available to generate power approximately in the high 80% of the time. Wells recalled that one time it was 87% of the time. Wells does not agree that the plant is broken. Wells testified that from a cold start, the subject takes seven to eight hours to come online. Wells stated that anytime the plant is offline for 72 hours or more, its going to be a cold start. A warm start would be a re-start from 48 hours to 72 hours of shut down, which would require a 3 to 4-hour start-up time. A hot start would be only about two hours or two and one-half hours after being offline for less than 48 hours. Over the course of his employment, after repowering the plant, they put in small boilers and vacuum pumps in the condenser to keep the turbines hot and removed the air ejectors to improve start-up times. Wells stated that one of the biggest problems in restarting the plant was the old turbines had to be heated up. With the small boilers, the turbines are kept at a hotter temperature so that a cold start becomes more akin to a warm start, which decreases the start-up time. Wells described the vacuum pumps worked to pull a vacuum on the condenser to create a load. Because the air ejectors worked on high pressures, they had to get the heat recovery steam generators up to 950 pounds of steam pressure, which took quite a bit of time. With the vacuum pumps, they kick them on then they pull the vacuum right out of the condenser. Because of these actions to improve start-up time, the turbine roll time was lowered. Wells explained that the old turbines are not as high tech as the new turbines and have to warmed up real slow. When they were cold, before they put the small boilers in, they had a five-hour warmup roll just on the turbines. A roll is when the throttle valve is opened, and you start spinning the turbine which may sit for three hours in that condition, called a soak period, wherein the turbine stretches (expands) out as it rolls. Wells stated that the roll time was shortened and the start-up time from a cold start was reduced to four hours.

Wells did not agree that most of the problems associated with failed starts were related to failed start-ups. Wells testified that the equipment is ready to go at any time and that a failed start can happen at any time, but it is not because of the equipment, it may be because of a management decision. After the post conversion period, Wells stated that in his capacity as an operating engineer with 39 years of experience in the subject plant, failed start-ups related more to managerial decisions rather than equipment failure. Wells testified that after Rockland Capital took over, they brought in a person that wanted to operate the plant in a way it could not be operated. He said they tried to put the units on time after time the way he wanted to do it, however, they told him they could not be put on (turned on) that way, and it failed time after time. Wells testified that the person wanted the turbine to be brought on in real low pressure with a low load on the combustion turbine and there was not enough pressure on the air ejectors to get a vacuum on the condenser. He explained that the combustion turbine had to be run at about 40 to 50-megawatts to get the pressure up on the heat recovery steam generator to run that piece of equipment. The vacuum needed to be run so you can roll the turbine which if the

vacuum is not run, the roll of the turbine could not occur. They needed so many inches of vacuum and the person did not want to start it that way, he wanted to keep it low and it would not start, they tried and there were a lot of failed starts. Wells characterized this as a management decision, not an equipment failure.

Wells stated the heat recovery steam generators generally functioned and, in his experience, never caused a failed start-up. He did not agree that they spent years battling the valves on the heat recovery steam generators. He stated the duct burners were operational as of January 1, 2014 and that the Grand Tower plant personnel did a good job of maintaining the systems and equipment in the subject plant. Wells testified that when he first started employment in the 1970s/1980s, they had a scheduled maintenance plan at the plant. Every other year they would tear down the two steam generators to some degree to check the seals and blades and to look for cracks. He said this was done every other year all through the 1980s. Wells stated the subject's steam turbines are Westinghouse and are considered the "Cadillac" of steam turbines. He said they were built in the 1950s and contain so much steel and they just run and run and run.

Wells testified that after Rockland Capital purchased the plant they had a meeting and a person came in and talked about how tough it would be to get people there because there was nothing there for anybody, which really upset the local people. This also made Wells mad. Wells testified that Rockland Capital tried to operate the subject plant as a peaking plant. Wells did not agree with this decision as it was hard on the equipment, mostly hard on the steam turbine. He said it is not a combustion turbine, but, they were trying to do stuff to damage the steam turbine. Wells said the subject was capable of running as a base load plant and was designed to run as a base load. He said you could put the subject on and they would run for 2 to 3 months at a time, it would sit there and hum with no problems. Wells testified that he recalls an instance where the subject plant ran in base load. He stated that after they went to lock the MISO dispatch, the employees had not been told of the different ways of running the subject. They always ran in a dispatch mode where they would turn the plant over to them at a certain megawatt and they would operate the plant. When it was really hot, and the megawatt prices were high, someone called wanting to know if Grand Tower could get more load, so Wells put the subject in base load which takes control away and lets the unit go to wide open. He stated the subject was able to pick up several megawatts on each unit. When Wells talked with the dispatch the next day, he was told the dispatch personnel got bonuses for the extra megawatts because they needed as much power as they could get. Wells testified that based on his experience the subject plant could be converted from a combined cycle gas turbine to a simple cycle plant by simply putting bypass stacks in. Wells stated they looked at that option, but it was going to cost a $1 million and the exhaust would be lost to the atmosphere, plus there were pollution concerns, so they decided not to do it. Wells testified that the subject plant could be operated as a peaking plant using a simple cycle if it had a bypass stack. He stated further that the plant could be operated as a base load plant or an intermediate plant.

He did not feel the plant was junk. He said they spent $300 million and has been kept up and run as needed. Wells felt the subject was a good candidate to convert to natural gas because less than a mile away from the plant is a natural gas pipeline which crosses the river, so they had a fuel source right there without having trucks driving 30 miles to deliver coal.

During cross-examination, Wells testified that the dispatch people were employed by MISO, a Midwest dispatch unit from Illinois and part of Kentucky, Indiana and Iowa that controls the power. Wells explained that once they got the subject plant running they would turn the plant over to MISO and there would be a dispatch mode that they could select. They always selected that mode and that is what they usually wanted because MISO could swing the plant. He sated Grand Tower with those combustion turbines could swing faster than most coal plants because coal plants required mills to be put off and on. But, Grand Tower's gas plant could swing a lot faster, so they were kind of a swing plant and could swing a load a lot faster, the megawatts, than maybe a big coal plant. Wells testified that MISO uses the power as needed. If MISO did not need either a base load or an intermediate plant, they would utilize the subject as a peaker plant. Wells stated that MISO brings the plants online with the wind turbines coming on first because they produce less pollution and are cheaper, then the coal plants. He stated the wind turbines produce more electricity now, probably 5-megawatts, whereas when they first started they were producing about one-half-megawatt. Wells stated they have tiers of how the plants come on, and they decide what the load's going to be for the day and they will look to the wind turbines to come online along with certain load base coal plants, then they will start looking at the gas plants. After that, he said MISO will then get so many peaker plants online and then they will look at the Grand Tower Plant for base load.

Wells testified that in 2008 and 2009 the duct burners sat a lot, and because of this drew a lot of moisture which required a lot of work to get them operational. Wells stated that subsequent to 2008/2009 they were out of commission and needed maintenance to bring them up. Wells reiterated that all the coal was removed, however the ash pond was left, which is not desirable to have on the site. Wells testified that the ash pond needs remediation and remains an ongoing issue. He stated the EPA is talking to the plant about capping the ash pond with soil, putting a crown on it and planting grass. He said they have monitoring wells around it to see if it is seeping into the groundwater. Wells believed the EPA is satisfied that a crown with grass will alleviate the problem, which would be much cheaper than hauling it off to a landfill. Wells testified that the biggest thing with the steam turbines is that they are older, and they have to be heated to stretch out and expand for the life of the turbine. By having them already heated, they can come on a lot faster whenever they call for the units because the metal is already stretched out and expanded. He explained the seals have to be heated also. Wells does recall that the steam turbines had cracks which required maintenance work on them. He stated the would pull the rotors and blades out and x-ray them. This work was done on-site, but then their maintenance was cut back so much that they could not handle the job, so they had to then send one of the rotors off-site to be redone.

Wells testified that the maintenance was cut back by both Ameren and Rockland Capital. Wells testified that to the best of his knowledge that as of January 1, 2014, the duct firing was worked on and they got it repaired. Wells does not recall any time that the plant was offline because of no water. He recalls they dredged the river and may have run at a reduced load because at one time it was really hot and if the condensers get hot, you have to reduce the load. He recalls a 20% reduction on unit 3, however, unit 4 was okay. Wells stated the plant did operate for only 3 months of the year during the downturn in 2008/2009 and maybe part of 2010. During that time, they operated only in the summer months. He remembers, because he was the only person out there at the plant. Wells testified that during that time, during the shut-down, they laid off

everybody and basically just had one fire watch guy and one guy out on the gate, with everything shut down and mothballed through the winter. Wells stated that he stayed inside and checked the pumps. He stated that because of seniority, he and four other guys rotated shifts 24 hours a day to keep an eye on the plant. Wells felt that it was during this time that the duct burners and heat recovery steam generators got in disrepair because they were not being used. Wells testified that in 2001, everything at the plant was brand new, they had four units operating. He said they had a few glitches on tuning of the valves, but most of it was more with computer issues and getting the valves tuned correctly. He does not recall expenditures being used at that time for several years. Wells said they started putting the small boilers and vacuum pumps in for pre-heating at or about 2015. As of January 2014, the subject took seven hours to start-up from a cold start.

Wells testified that prior to 2001, when the plant was coal-fired, they could get 84-megawatts on unit 3 on a good day and about 107-megawatts on unit 4 with the coal boilers. After 2001, the steam turbines were reduced some so they would get about 78-megawatts out of unit 3 and probably 92-megawatts out of unit 4 with normal on each combustion turbine (units 1 and 2) of 170 to 186-megawatts, depending on temperature, moisture and the conditions. If it was cloudy or rained, the combustion turbines might pick up 10-megawatts. Wells testified that post 2001, in the winter when it was cold and damp conditions there were times they got the subject up to reaching nameplate megawatt capacity. He recalls that when they reached that level, they called the engineer to ask him if the subject was rated to that level or was it rated to a certain percentage over that level. Wells testified that this occurred several times, probably in 2003 or 2004 when they had some really good runs through the winter months. Wells stated this also occurred a couple of times in 2015 after they got the duct burners up and running. Wells testified that the nameplate capacity for the entire plant was in the mid-500s.

Wells testified that as of January 1, 2014, the subject was operating in good condition with no major flaws. Wells does not know of any time the subject plant was run any less than other plants like the subject. He said the plant is run per what MISO wants and if it is run at a lower capacity, it is because that is what MISO determined it wants. He said the equipment is always run at max power and is dependent on the weather, whereas if it is hot and muggy the subject is just not going to do as well and that is where the duct burners come into play. He testified the duct burners are more expensive, but they will give you more power in those conditions. In 2014/2015 they were trying to operate the subject plant as a peaker plant and they were doing everything they could to shorten the roll times, trying to bring the steam turbines on in ways he had never seen, which could damage them. Wells testified that he did not believe, Rockland Capital knew what they were doing. Wells stated that the only time the old equipment affected the subject, was during start-up. It was designed to come on slower, but, with the additions of the heat systems they put in and the vacuum pumps, they alleviated a lot of those problems. Wells testified that in 2014 and 2015 they were trying to bring the subject online faster than it should have been; faster than it was designed for from a cold start.

The next witness called by intervenor's counsel was George Lagassa, PhD, ASA. Lagassa identified intervenor's Exhibit No. 5 as the 2014 and 2015 appraisal reports he prepared. He stated the 2015 appraisal was completed prior to the 2014 appraisal by about 3 weeks. Lagassa inspected the subject property on November 14, 2012 wherein he met with the operator of the plant for about an hour to get a lay of the land. He then looked at the steam turbines, the heat

recovery steam generators, the combustion turbines, the river intake and the various piping that was present. He also examined the large building, which he described as surplus now that it only holds the steam turbines since it had previously housed a lot of coal facilities. Lagassa testified that he has been practicing appraisal since 1983 being first licensed in 1996. He is an accredited senior appraiser in machinery and technical specialties from the American Society of Appraisers. Prior to becoming an appraiser, he worked as a power plant developer for a hydroelectric company based in Boston. He then worked for several years going around to look for plants to buy. Prior to that, he was a college professor and taught at the University of New Hampshire. His PhD is in political science/public policy and his PhD thesis was on electrical utility regulation in New York State. As of the date of the hearing, he has appraised hundreds of power plants ranging from very small to this kind of natural gas facility. He has appraised coal generation projects, wind, solar, hydroelectric, diesel, nuclear, coal and waste-to-energy projects. The sources of information in his appraisal were based on information he requested, interviews with operating personnel prior to his tour of the facility and information he received from the company and based on his independent research. He stated that online, there is a lot of public information from the Federal Energy Regulatory Commission and the Energy Information Administration. In addition, there is information published by MISO regarding the prices for power and demand for power and the state of the market in the MISO region.

Lagassa described the subject plant as being very well located about a mile away from a good-sized Kinder Morgan pipeline which makes it ideal for natural gas. This is one of the reasons the subject was converted to natural gas because of the availability of the fuel source. He testified that the subject was also conveniently located on the Mississippi River as a consequence of which it has an abundant source of cooling water. It is also located next to a substation that is a transit point for 138 kV transmissions. He explained these are extra high voltage transmission facilities of several 69 kV lines which are called sub transmission and are definitely a significant means of getting the power out of there. He described the subject plant as being located relative to various urban area, so it was expected there would be a continuing demand for the power being generated from that location relatively close to Chicago, St. Louis, Louisville and Indianapolis.

Lagassa testified the subject plant as originally developed as a coal burning facility, a pulverized coal operation, constructed in the mid-1920s. Two steam turbines were originally installed (units 1 and 2) and then in 1951 and 1958 units 3 and 4 were installed with units 1 and 2 being retired. In 2001 the decision was made to convert to a combined cycle gas generation, so units 1 and 2 were installed, which would have the combustion turbines and the heat recovery steam generators associate with them. Lagassa determined the installed capacity for the subject plant was 570-megawatts, which was the sum of the nameplate capacity as offered to him in the documentation. He testified that it was a combination of the two 185-megawatt capacity combustion turbines, combined with one 85-megawatt steam turbine and the other 115-megawatt steam turbine. Lagassa stated he relied upon intervenor's Exhibit No. C to derive his calculation of the subject's capacity.[8] In regard to the subject's condition, Lagassa stated he had visited newer combined cycle plants in Texas and the subject seemed to shape up very well by

[8] Intervenor's Exhibit No. C was offered in both the 2014 and 2015 appeals and was a document provided to the intervenor as part of a document request to the taxpayer, Rockland Capital.

comparison. He testified the condition of the combustion turbines and the heat recovery steam generators were excellent considering that they had only been installed in 2001/2002. He found the steam turbines were well maintained and he concurred with Wells that they could run forever. Lagassa testified he has seen studies that indicate a 65 to 75-year average service life. Looking at FERC Form 1, the annual report of major electric utilities, which at the time Ameren was, and looking at the Energy Information Administration Form 923, there is information about the operation of the subject plant, which indicates the gross generation, the net generation and the amount of fuel used in volume of fuel and also in heat content or millions of BTU. Lagassa was able to determine the subject's operational history all the way back to 2001 since it was first converted to natural gas. Lagassa stated that the average capacity factor for the historical life of the plant post conversion was 7.9% over the 14-year time period. Lagassa testified that the average five-year heat rate immediately preceding the appraisal date of January 1, 2014 was 8.9%. In his opinion, the heat rate for the subject property was reasonable when compared with natural gas combined cycle plants that he has seen. When comparing the heat rate for the subject property to the heat rate of a simple cycle combustion turbine plant, Lagassa stated that at 7,500 to 8,000 BTU, which was well below what you would expect from a simple cycle which may be in the order of 10,500 to 13,000 BTUs depending upon how frequently they are operated. Lagassa testified that the subject is considerably more efficient in operations than a simple cycle combustion turbine plant.

Lagassa testified that he examined the operating costs relative to buying the right to pollute the air and determined and was told that when he visited the plant the installation was sufficiently efficient, that its emissions were very, very low and that the emission allowances that were purchased were quite minimal. He confirmed this by looking at the FERC information and was able to come up with a number, but, it did not seem to have a whole huge effect on the net operating income because it was low.

Lagassa testified that it was explained to him when he visited the plant that in 2009, 2010 and 2011 Ameren had made the decision to not operate the plant more than three months out of the year as they had concluded it was uneconomic to operate during the other months and wanted to limit expensive operation during the full year. Lagassa opined that it was probably the result of high gas prices which peaked in 2008 and 2009.

Lagassa explained that certain types of plants are generally considered to be base load and certain types of plants are generally considered to be mid-level, mid-merit, intermediate or shoulder load in operation. And, certain types of plants are considered to be peak plants. He stated they have different characteristics based on the amount of operation. A base plant is going to be operating all the time, 24/7, then you might be more inclined to spend more money on its initial installation because you realize it will be amortized over all those hours of operation. Generally, base load plants involve much larger capital, and outweighs the operation and maintenance costs. He considers plants that operate from 23% to 57% of the time to be intermediate load plants and those that operate more than 57% of the time to be base load with plants operating less than 23% of the time being peak load plants.

In regard to the future outlook of operations of the subject plant as of January 1, 2014, Lagassa stated that to him the subject plant was mirroring changes in natural gas prices. He stated natural

gas prices had peaked in 2008/2009 and then went down as a result of new means of drilling and because they have been able to gain access to more and more natural gas. So to him, it means that as a highly efficient combined cycle unit with a heat rate on the order of 7,500 to 8,000, depending on how often it operates, and the BTU per megawatt hour with the expectation given lower gas prices would be that this subject plant would operate more frequently, that there would be incentive for it to operate more frequently and that the prospects for the plant were bright as opposed to dim. He stated this was also encouraged by virtue of the fact that it had been announced that numerous coal plants in the region were being shut down, so that this would take a new place in the merit order on the dispatch schedule as the coal plants which he generally thought to be cheaper in operation would be removed from that. The demand for this plant would increase, plus the economy at this point was picking up. In summary, as of January 1, 2014, the prospects for increased operation were obvious.

Lagassa's report describes on page 36 that gas-fired combined cycle plants have emerged as the power source of choice because they offer the best heat rates relative to a simple cycle with heat rates of 12,000. In addition, gas-fired combined cycle plants are environmentally clean. Lagassa testified that he considered the subject property's sale but did not give it a lot of weight primarily because the final purchase price for the property was unknown as there were a number of transactions that were occurring at this same time period. Further, Lagassa testified that what appeared to be the final transaction was not really the final transaction because it indicated that if the subject plant were subsequently sold, then the seller, Ameren, would be reimbursed for whatever the difference was. Lagassa stated that in the financial press it was indicated that when Ameren sold all of its coal plants, they would receive $180 million in future tax benefits because they did not receive any cash compensation, just an assumption of debt at that point. Lagassa stated that Ameren announced in March of 2013 that they were getting out of the unregulated merchant power business and were going back to the haven of regulation, so, they immediately transacted the sale of the coal-fired facilities and then subsequently about a month later announced the sale of the three separate facilities, which included Grand Tower.

Lagassa testified that based on his experience as a developer of hydroelectric stations, if you wanted to buy plants, it was a long and involved process. There may be a separate financial advisor such as Morgan Stanley or Goldman Sachs or a bank hired to provide advice and consulting. Then there may be a document room where a potential buyer would be brought in to be interviewed to see if they were qualified buyers and the field of potential purchasers would be narrowed down from ten to three or so. He stated that process could take at least a year if not longer to complete for plants of this scale with megawatts over 500. He estimated the marketing time of the subject plant should have taken 12 to 18 months. When the two simple cycle plants are added into the mix, it adds to the complexity of the due diligence that would have to be done by any potential purchaser.

Lagassa looked at all three plants involved in the sale of Grand Tower. He examined the actual experienced operational heat rate from the FERC Form 1 of the Elgin and Gibson City plants and looked at the Grand Tower data from the EIA 923, which indicated a considerable difference. He stated the Gibson City plant had an average heat rate over the five-year period of double that of Grand Tower. He found Elgin was also considerably higher. So, based on those plants being less efficient, his conclusion was that Grand Tower, being certainly bigger in scale than Gibson

City, a strong argument could be made that the highest value of the three plants involved in the portfolio sale would be the Grand Tower station. In addition, it was clear to him that Grand Tower had the highest capacity factor over the past fives years when comparing the three plants. He stated the capacity factor average for Elgin was 1.19% and Gibson City had 1.07% with Grand Tower having an average five-year capacity factor of 8.91%.

Lagassa testified that Grand Tower met all four tests of possible use, permissible use, feasible use and maximally productive use for highest and best use as a combined cycle natural gas burning facility.

Lagassa stated he considered the sales comparison approach to value reviewing 18 sales; the cost approach to value using both the reproduction cost and replacement cost, depreciated; and the income approach to value, pursuant to which he developed a discounted cash flow model.

His cost approach to value can be found on page 42 of intervenor's Exhibit No. 5. In the cost approach to value, he differentiated between the value of land and the value of the improvements, then determined a replacement cost of the improvements, determined the extent of depreciation and subtracted that to come up with a replacement cost new, including or not including, the replacement cost new less depreciation.

In developing his cost approach to value, one of the pieces of information he requested from the owners was a fixed asset ledger which would indicate the original cost at the time and vintage age of the various remaining surviving assets there. He then applied, as is convention and routine, the Handy-Whitman Index of Public Utility Construction Costs to that and determined that the reproduction cost as of January 1, 2014, of the old steam turbines together with the newer combustion turbines and heat recovery steam generators and of all the ancillary equipment that had not been retired would have been $748,503,000. Lagassa concluded that the most likely replacement for the subject facility be a conventional natural gas combined cycle facility, the costs of which are outlined in detail in publications by the Federal Government Energy Information Administration. Lagassa testified that he did not use a simple cycle combustion turbine plant as an appropriate replacement for the subject because it was an intermediate operating facility. In addition, a simple cycle plant has much higher heat rates and it would be foolish to use that as a choice. He also did not use an advanced cycle plant as a replacement for the subject because the operating costs indicated in the Federal Reports were higher on a fixed cost basis and slightly lower on a variable basis. He thought the heat rates were a little bit better and would probably have come out the same.

On page 43 of his report (Intervenor Exhibit No. 5) Lagassa explains that a natural gas combined cycle plant has a quicker start time in comparison to a coal or nuclear facility; hence it qualifies for operation with an intermediate range, a mid-merit plant. Lagassa's replacement cost analysis was based on the published data from the Annual Energy Outlook for 2013/2014 where price per installed kilowatt for a conventional natural gas combined cycle facility was stated at $901 as an overnight cost. He stated the overnight cost excludes certain costs primarily related to project finance, allows for funds used during construction or construction interest. In addition, the overnight costs at the subject had to be adjusted for its location within a particular operating power pool, which was SERC-Gateway. Further, a change was made because the price per

kilowatt was based on a 620-megawatt comparative facility; whereas, the subject was slightly smaller, so adjustment was needed for economies of scale of the larger versus the smaller plant. After all of the adjustments, Lagassa concluded that the cost per installed kilowatt of a conventional combined cycle of 570-megawatts would be $1,004 per kilowatt, which amounts to $572,280,000. He then added the allowance for funds used during construction (interest during construction) which he calculated assuming a three-year construction period and interest at prime plus 100 bases points which seemed reasonable. He then added in the value of the land.[9] The total, exclusive of land for the cost to replacement was $617,232,000.

Lagassa testified that in order to calculate incurable physical deterioration he basically used the age-life method somewhat refined by determining an effective age based on a dollar weighted replacement cost versus an actual replacement cost. Lagassa testified that this was a standard procedure used by machinery and equipment appraisers for determining the age of a plant, or the effective age. After determining an effective age and a useful life for two different components, one would be the components that were installed after 2001 where a particular service life of somewhat shorter service life was assumed; whereas, a longer service life was assumed for the components installed prior to 2001 because that was installed for a coal plant. After computation, Lagassa determined that the extent of depreciation was approximately 55% or precisely 55.3% of physical depreciation as of January 1, 2014. He found approximately 67.3% of the assets or the expenses and costs incurred at the site were installed after 2000 and approximately 32.7% were installed prior to 2001.

Lagassa stated that functional obsolescence is the loss in value with a property as a result of the development of new technology, including such things as changes in design, materials, or process resulting in overcapacity, inadequacy, excess construction, lack of utility or excess variable operating costs. He stated that one form of functional obsolescence was excess construction which is measured by the difference between the reproduction cost new less the cost of replacement. A second form of functional obsolescence that he factored in was the more efficient operation of the replacement which had a stated heat rate of 7,050 BTU as opposed to a heat rate that he adopted of approximately 7,500 BTU. He stated the difference meant that the operation of the facility would be more efficient than the operation of the subject by that 450 BTU difference in the heat rate. Lagassa analyzed how much fuel would be consumed over a holding period going forward which is the same holding period he applied later on to his discounted cash flow analysis and determined that the present value of the additional operating costs associated with the subject relative to the lower heat rate of the comparable was $15,191,000. And, in order to properly compare the subject to the replacement facility, it required that amount be subtracted from the numbers that were adding up to the final conclusion of value by the cost approach.

In addition, he had a computation for two forms of external obsolescence. One for being the obsolescence imposed on a facility by virtue of events that occur outside of the asset itself. He explained the first one is the cost of complying with orders by the government to do certain kinds of environmental cleanup. After looking at the numbers given to him by the owners with respect

[9] The witness did not testify as to the land value since the parties stipulated to the subject's land value prior to the hearing.

to their budgeted capital costs associated with those expenditures, he determined a net present value of $5,609,000 needed to be subtracted for external obsolescence.

Lagassa also did a comparison of the subject facility by comparison to the operation of the replacement less physical depreciation to determine how much additional income would be required in order to make it possible to justify the expense invested in the subject plant. He determined that the difference would require an additional 25.5% of income year after year after year in order to justify that expenditure. So, he deducted 25.5% from the balance of the numbers that he computed up to that point to determine a total amount of economic obsolescence (see page 49, intervenor's Exhibit No. 5). Lagassa found the excess construction which was the difference between reproduction cost new and the cost to replacement was $131,271,000, which was subtracted. Physical deterioration was subtracted from the cost to replacement at 55.3%, resulting in a balance of $275,902,000. He then subtracted 25.5% of that for the revenue deficiency associated with the increased cost of operation of the comparable. He then also subtracted separately those other numbers for functional obsolescence and external obsolescence, re-added the value of the land and came up with $185,600,000 as of January 1, 2014.

In developing his sales comparison approach to value, Lagassa examined 18 separate sales transactions involving 25 different plants. He testified that some of the combined cycle sales were portfolio sales wherein one of the sales contained a simple cycle plant, but, the bulk of his sales were combined cycle natural gas-fired plants of similar scale to the subject. The one simple cycle plant was part of a portfolio transaction that included a number of natural gas combined cycle plants.

Lagassa considered all of his comparable sales were of similar vintage when compared to the subject; all were 1993 and 1994 sales, with the exception of sale number 5. Lagassa concluded that 16 of the 18 sales comparables were comparable in scale to the subject with respect to capacity. He stated they were in the 400 to 650-megawatt range, which he considered to be of similar scale. He cut them off if they were smaller than 400-megawatts. In regard to location, Lagassa testified that the Holland Energy Plant sale in Illinois was similar to the subject in location. He stated the plants that were sold that were located in the southern markets were probably more similar to the MISO market than the plants sold in Texas or in New England which had a healthier and more robust market for energy and capacity. Lagassa stated that the average sale price of his 18 comparable power plants was $487 per kilowatt. (see page 56, Intervenors Exhibit No. 5) Lagassa concluded a value for the subject of $386 per kilowatt, or $220 million. Four of his comparable sales sold for less than $386 per kilowatt and 14 sold for above $386 per kilowatt. Lagassa found sale number 18 to be most similar to the subject primarily because it was of similar scale, similar vintage and was purchased in Illinois and was operated at pretty much the same as the subject after looking at the operating history over the preceding years and subsequent years to 2014. Lagassa stated it continued to operate at a similar capacity factor to the Grand Tower station. (see appendix B, Intervenor's Exhibit No. 5) Lagassa testified that the Holland Energy Plant had an estimated capacity factor of 8.32% with an estimated net heat rate of 7,931 in 2013. In addition, in 2012 it had a net heat rate of 7,433 with an estimated capacity factor of 17.58%. The five-year weighted average capacity factor was 10.25% with the five-year estimated heat rate of 7,786. Lagassa testified the Holland Energy Plant was a combined cycle facility in the MISO market in Illinois and sold within five

years of the date of value in his report. Lagassa stated this plant was of similar size to the subject and of similar vintage to the subject. On page 56 of his report (Intervenor Exhibit No. 5) Lagassa adjusted the New England and Texas sales downward because he concluded that these markets were superior to the MISO market. Based on his experience and having done a lot of appraisals and studying various markets, he concluded a deduction of 30% was appropriate. When looking at the heat rates of his comparable sales, Lagassa stated they were all slightly better than the subject, but not dramatically better, they were 7,200/7,300 as opposed to the average he used of 7,500. In regard to concluding a value for the subject based on his comparable sales, Lagassa testified the he concluded a range.

He testified that there were lots of plants that were sold that were natural gas combined cycle, similar vintage, similar capacity factor and so on. He testified that it was difficult to draw conclusions because much of the information about these plants is not publicly available, so he needed to look at the general marketplace and it seemed appropriate to establish a range than to indicate a single point indicator of value. Lagassa determined a range of approximately $186,390,000 based on a price of $327 per kilowatt. Lagassa stated this would be the low end with a high end being $271,890,000 based on $477 per kilowatt, computed largely off of the Holland Energy facility sale. Lagassa testified that these plants, if properly marketed and given the full 12 to 18 months that might have been required to get a good sale price would legitimately command a price within that range.

Lagassa next testified regarding his methodology for completing his income capitalization approach to value. Lagassa stated he utilized a discounted cash flow analysis as opposed to a direct capitalization approach. Lagassa testified that a direct capitalization would be appropriate if you were able to discern or extract a capitalization rate from the market. Lagassa stated, that for example, with a shopping center, you could determine how much it sold for and multiply that by its net operating income and come up with a cap rate or a multiple. Lagassa testified that the direct capitalization method was not possible here because the information about plants was not sufficient to establish that, so it seemed appropriate to him to utilize a discounted cash flow analysis. In addition, it was because the income is variable over time and not necessarily predictable in one direction or the other on a steady basis.

He testified the discounted cash flow analysis is superior because it is able to capture those differences in a way that a direct capitalization cannot. Lagassa stated the subject has an installed capacity of 570-megawatts, however, for purposes of determining the capacity payments, he saw from a publication of the GADS material and from information provided to him from Rockland Capital that the actual operating capacity for the subject was often in the 300 to 400-megawatt range. For this reason, he posted an initial capacity of approximately 300-megawatts and improving over time as his expectation for increased operation was fulfilled up to 475-megawatts. Lagassa stated that the capacity factor was for the purposes of determining energy output. Lagassa determined that the five-year average net capacity factor at the subject site from 2009 through 2013 was 8.9%; five-years immediately prior to the appraisal date. Based on his expectation that this would improve for all of the reasons previously indicated, he concluded that it was reliable and predictable that the subject plant would continue to operate at a slightly better than 8.9% factor going forward, so he concluded a 9.5% capacity factor. Lagassa testified that those capacity factors are based on a capacity of 570-megawatts. He stated that if

he had used a different capacity, the capacity factor would be different. Lagassa stated that what is important is the amount of energy he is projecting, not the capacity factors. Lagassa testified that the purpose for doing this is to determine how much energy is generated, and that is based on the relationship between some stated capacity and the number of hours in a year and what it could potentially generate. Lagassa stated a 570-megawatt plant can generate a lot more than a 530-megawatt or 55-megawatt plant. He stated those capacity factors might change, but that is not important, what is important is the amount of energy that is forecast as a result of the relationship between the number of hours in the year and the assumed installed capacity. Based on this, using a 9.5% capacity factor, he was able to forecast an expected annual energy output of 474 million kilowatt hours, approximately. One of the reasons he went above the 8.9% capacity factor in his analysis and based on his conclusion that the subject would increase operation from the five-year preceding average, was because Ameren was no longer under the business decision to shut the plant down for the peaking months. In addition, Lagassa stated he knew natural gas prices were going down and then were expected to grow very slowly. Further, they also knew that coal plants were being shut down and nuclear plants were generally expected to shut down, excepting Illinois, which had somewhat changed. But, as of January 1, 2014, there was the expectation that several nuclear plants, including Clinton, were potentially going to be shut down.

In regard to looking at the subject's trend taking into account the operations of the plant over the five-year period, Lagassa stated that 2009 was the worst year because of the peak in gas prices which were topping out. In 2009 the gas prices began to fall and in 2012 had fallen rather precipitously and as evidence in previous testimony by Wells, the subject was able to operate at a much higher capacity factor on the order of approximately 25%. Lagassa stated that in 2013 the subject went back to 9.4%, which is approximately what he had indicated. He did not think that was an unreasonable expectation that the subject will continue to operate at that level or at approximately that level.

For his discounted cash flow analysis, Lagassa used a heat rate of 7,500 BTU per kilowatt hour. In regard to sources of revenue for the subject, Lagassa indicated there are basically three products that are produced, 1) energy, 2) capacity and 3) ancillary benefits. Lagassa computed the amount of energy based on a 9.5% capacity factor which indicated 474,354,000 kilowatt hours per year going on into the indefinite future. Lagassa determined that the base price for electricity in 2013 in the subject's region was $45 per megawatt hour. Lagassa then opined that going forward the price would change, increase or decrease along with the price of natural gas. He stated this was a known and accepted fact, that electricity prices are driven by the price of natural gas. So, he sought out legitimate and reliable forecasts of natural gas prices going forward which were sourced from the Annual Energy Outlook published by the United States Energy Information Administration. Lagassa then took the $45 per megawatt hour and changed it going forward for the subsequent years in lockstep with the change in the price of natural gas.

Lagassa testified that capacity, in reference to revenue, was a reimbursement for being available when called upon. Lagassa stated that the market for capacity in the MISO region has been the subject of controversy over time. He said they had some difficulty establishing the market, but, by the time 2014 came around, the voluntary capacity auction that had been established by the Illinois Power Agency or Power Authority was $16.75 per megawatt day, so that is what he

posited. Utilizing the knowledge that capacity was based on the cost of replacement of a new facility, which is called "CONE" or the cost of a new entry, which is to say how much would it cost to build a new plant, the discussions were circulating that the prices and penalties that were established for people who defaulted on the provision of their capacity was on the order of $65,000 to $80,000 per megawatt year, which computes back to some number. So, Lagassa's expectation was that as MISO was becoming more and more attuned to the need to reimburse capacity properly and become more and more like PJM with which it has become more greatly integrated, that it was reasonable to conclude that the $16.75 per megawatt day which had been established for 2014 would increase in the future, in the immediate future years.

His personal judgment in his 2014 appraisal, which is slightly different in his 2015 appraisal, but not dramatically, he concludes that it should increase, which is why he doubled it in 2015 and again in 2016 until he reached $90 per megawatt day, which is approximately half of the cost of new entry. It seemed to him that it was a reasonable forecast as to what capacity prices might do going forward. As indicated earlier, he used 300-megawatts as the installed capacity gradually creeping up to 475-megawatts because that would be the incentive of a responsible operator to improve on that number. Lagassa computed capacity income from that computation, the stated installed or stated operable capacity from 300 to 475-megwatts times the number of dollars per megawatt day. For his third source of revenue from ancillary services, he looked at the new ancillary services market in MISO. It was reported to him from Ameren or Rockland Capital that their annual income in 2014 from ancillary services, which would include mostly voltage regulation or load in such a way as to ramp up and ramp down as called upon, that those services produced $2,241,000 of income. Lagassa inflated that income going forward with inflation for purposes of determining what it would be going out into the future. Lagassa stated that you add them all up and you come up with gross income from the three different sources.

In regard to the operating expenses as shown on page 63 of his appraisal report, Lagassa stated that in 2007 the subject plant operated at a similar plant factor to that which is being estimated there. At that time, he stated that according to FERC Form 1, the non-fuel operating costs were $0.93 cents per kilowatt hour to bring those up to 2014 level, so he escalated them at an inflation rate of 2% and came up with a number of $1.068 cents per kilowatt hour, which he rounded up to $1.07 cents per kilowatt hour. Lagassa stated that as of 2014, based on its operation in a very similar year in 2007, he determined an operating cost of $1.07 cents per kilowatt hour and then in future years he inflated that again. Lagassa testified there is definitely a correlation between the amount of electricity generated and operating expenses. He stated there are fixed costs, but the variable costs will increase per kilowatt.

Lagassa testified that the owners provided him with a number of different estimates of actual and forecast capital expenditures, and he simply adopted the ones that they provided for a 2006 to 2011 forecast with one exception. He stated there were expenses for ash remediation which were included, but those for fish and aquatic resources, he excluded because those were not established till the end of 2014 by regulation. As of January 1, 2014, there was not expectation that that expense should be in there. Lagassa stated this was a minor adjustment, he simply adopted the CAPEX projections provided to him. He used a capital expenditure of $2,733,839 for year 1, which was based on actual expenses given to him by the owner. Lagassa testified that a very high or inflated capital expenditure in year 1 can have a negative impact on the value of a

property because it is essentially a direct deduction from the value because it has not been discounted. On page 70 of his appraisal report, Lagassa posited an expected return of 11.2% on equity. He stated, however, that he also factored in a flotation cost, which means in order to sell that product to the financial market, he posited a flotation cost of 4.5% so when you compute the overall impact of that, the return on equity required would be 11.7%. Lagassa testified this was compatible with the reported returns on equity listed on page 67, figure 12 of his appraisal report. Lagassa stated that on an equity investment, you are earning a return of 11% annually. He noted that in 2014 the actual return on equity as reported in Yahoo Finance for AES, which is an independent power producer, was 15.54%. For NextEra, which is a utility which owns independent power producer subsidiaries, it was 12.92% For NRG, which is largely an independent power producer, it was only 1.16%. Lagassa found the average to be 9.75%, so the 11% he posited was compatible with the sort of broad mixed market that he thought would be out there to purchase a facility of the subject's nature. Lagassa explained that figure 12, on page 67 of his report depicts a 19% return on equity substantially higher that what was actually experienced by typical companies that participated in the market at that time period. Lagassa explained that the focus should be on AES, NRG, NextEra and PPL as much of their investment is in the form of independent power producer subsidiaries, and so their return on equities were much lower. Lagassa concluded a value for the subject under the income approach to value of $231, 220,000 as of January 1, 2014.

In reconciliation, Lagassa testified that he weighed each approach equally. He stated he did not take an average and used his judgment. Lagassa looked at each approach to value and tried to determine which provided reliable information that he thought where adjustments could be made, that had to be made that were based on assumption, that those would probably represent the weakest indicator of value. Lagassa felt the cost approach might have presented the weakest indicator of value simply because there is a huge deduction made of 25% from the replacement cost new less depreciation for his value by the cost approach. He felt there was some reason to express concern about the cost approach. Lagassa opined that the market approach was particularly useful because it established a broad range of values and looked at a broad range of potential purchasers of these plants, including independent power producers, equity funds, hedge funds, utilities and utility subsidiaries. Lagassa felt this was a very broad market of potential purchasers of these plants within that range based on similar vintages and seemed to offer a pretty reliable indicator of value within a range. Lagassa testified that the income approach to value was based on pretty detailed information about the expected income, the assumptions there were with respect to expected price for these things going forward. Lagassa did not think that his forecast of energy prices and capacity prices were dramatically different than those via appraiser on the other side. Based on all of these things, Lagassa concluded a value for the subject of $220 million which was somewhere in the middle of the range or slightly more and slightly closer to the income approach and slightly further from the cost approach to value.

After deductions for intangibles, goodwill and furniture and equipment, Lagassa concluded a final value for the taxable portion of the Grand Tower power station as of January 1, 2014 of $101,112,000. As of January 1, 2015, Lagassa concluded a final value of the taxable portion of the Grand Tower power station of $91,963,000 (Intervenor's Exhibit No. 6).

Lagassa stated that the five-year net capacity factor in 2015 was the same as it was in 2014, however, he carried it out to one more decimal place shown as 8.92% as opposed to 8.9% in 2014. Lagassa testified that in 2015, he again used a capacity factor of 9.5% for the same reasons. For the 2015 heat rate, Lagassa used 7,588 based on a five-year average as opposed to 7,500 in the 2014 report. Lagassa stated that his cost approach on page 42 of his 2015 report had slightly different overnight costs and trended costs based on the different dates of value using the 2014 Annual Energy Outlook as opposed to 2014 because he inflated the figures.

Lagassa testified that his estimate of value for the subject as of January 1, 2015 based on the cost approach to value wherein he used the same techniques with slightly different numbers was an estimated value by the replacement cost new approach of $202,824,000.

In the 2015 sales comparison approach to value, Lagassa used only 12 sales transactions because the earlier sales used in the 2014 appraisal fell off the screen because he tried to incorporate things that were proximate in time. Lagassa testified that the 2015 appraisal report was prepared prior to the 2014 report. He stated that the sales at the bottom of list in the 2014 appraisal would have fallen off because he was trying to cover only a four-year period. Lagassa stated that at the time he prepared his 2015 appraisal, he either did not know of the other sales or that they seemed to be more utility oriented and he wanted to limit the examination to more independent power producers and exclude any bias that might be in there by including utility properties. Lagassa concluded a value for the subject utilizing the income approach to value for the subject property as of January 1, 2015 of $198,821,000. Lagassa estimated a value for the Grand Tower power station as of January 1, 2015 using the same logic, looking at the range of values in the market approach and seeing the cost approach and the income approach values which he thought were relatively close to one another, he concluded a value of $200 million.

During cross-examination, Lagassa testified he possessed the ASA designation in machinery and equipment. Lagassa reiterated that he is licensed in the State of Illinois because it is required to obtain a license in Illinois for real estate appraisals. Lagassa admitted that he has been disciplined by the Illinois licensing board and has been fined $25,000. In addition, he was disciplined by the Maine licensing board as it was related to the Illinois issue. Lagassa testified that he was disciplined once in Illinois for filing a report without a license and was fined and then he was disciplined by the State of Maine for failing to inform them within 10 days as required by their regulations.

Lagassa stated he inspected the subject property on November 14, 2012 with the only change he can recall being a transition piece that was cracked, which needed to be welded. He stated he tried to confirm whether or not the repair had been done and despite numerous requests, he was never informed of it. However, he did conclude that it looked like it had been repaired and made the assumption that it had been repaired and has proven to be repaired.

Lagassa agreed the subject property's sale closed in January 2014 along with three other properties [sic]. Lagassa testified that he knew what the sale price was and that there was a three-stage process, that the coal plants were sold separately, the gas plant was sold separately to Medina Valley, which was a subsidiary of Ameren Energy Resources, who then simultaneously or shortly thereafter transferred it to Rockland Capital. He believed the total sale time took 2 to

5 months. Lagassa testified that it would not surprise him that the subject property was on the market in the beginning of 2012. Lagassa agreed his 2014 report does not discuss the subject's sale to Rockland Capital in great detail, but since it occurred after January 1, 2014, he did not think it was inappropriate.

Lagassa testified that he notes on page 6 of his report that an extraordinary assumption is from a definition in the Uniform Standards of Professional Appraisal Practice that if there is something that needs to be true in order for a report to be valid, an appraiser should note it. So, he made the observation that his conclusion of value is based on forecasts of energy prices going forward. He testified that if they are not valid, then his appraisal results might be different.

On page 8 of his report, Lagassa stated the Grand Tower was in full operation as a merchant generating facility. Lagassa stated that he did observe that one of the units was suffering from some wear and tear owing to the transition piece, but, the subject was in full operation meaning it was fully operable with some proper maintenance.

Lagassa stated in his report that the subject has a nominal capacity of 570-megawatts which matches the nameplate capacity in this case. When discussing the 570-megawatts, Lagassa testified he is talking about capacity, not generation which is a measure of energy. He stated energy would be in kilowatt hours and capacity is in kilowatts or megawatts. Lagassa agreed the subject is a hybrid power plant insofar as the steam turbines were originally installed for a coal plant, but stated, it is not hybrid in the sense that it has the characteristics of a standard natural gas combined cycle plant. He stated it has the combustion turbines, it has the heat recovery steam generators and it has the steam turbines. He believed the subject is sort of a hybrid. Lagassa agreed it is abnormal in the industry to have two gas-fired combustion turbines paired with two older steam turbines. He stated you could have one steam turbine doing the same thing, but since there were two there, it made sense to make use of them. Lagassa testified that he had not done an analysis to determine the percentage where one as opposed to two steam turbines would be paired with a gas-fired combustion turbine, but it is not unusual to see it paired with two.

Lagassa admitted that in 13 years of operation the nominal capacity of the subject was only above 6% two times, in 2005 and 2006. Lagassa testified that the subject does not operate as long as or as often as a typical gas-fired combined cycle turbine. Lagassa stated that the nationwide average utilization of a natural gas combined cycle plant was 30% at that time, so the subject's plant factors are relatively low, just barely within the intermediate range. Lagassa reiterated he gave his cost approach to value analysis some weight and credibility and tried to view all three approaches to value equally but viewed the cost approach as least reliable because it involved the largest adjustment, which are typically found in the depreciation analysis he prepared.

On page 43 of his report, Lagassa admitted that he did not make an entirely accurate statement wherein he stated the natural gas combined cycle plant has the quick-start capacity of a peaking plant. Lagassa testified that it should have read they can offer the quick-start capability of a peaking plant, particularly if there is a bypass stack. Lagassa explained that he previously appraised some other natural gas combined cycle plants in Texas which did have bypass stacks

and probably made the mistake and assumption that they existed in the subject plant, which they did not. Lagassa stated it would be better to not even consider the subject as a peaking facility, but to think of it more as an intermediate facility or even a base load plant. Lagassa admitted that intermediate facilities were intended to operate at higher capacities than what the subject has typically been operated at, but stated it is sort of in the range and there has been instance where the operation is borderline of an intermediate. Lagassa agreed that it occurred in 2002 and 2012 but stated that peaking and intermediate are just a word, you can call it what you want, but, the important thing is how much energy you think it is going to produce going forward.

Lagassa agreed that the subject can produce all the energy in the world, but if there is no demand for the energy, who is going to buy it. Lagassa admitted that on page 48 of his report that instead of saying the subject facility may have incentives to remain offline, he would prefer to say that it could operate under capacity in order to ramp up or ramp down as the case may be, automatic generation control. He stated the subject does not remain offline and gain a benefit, but it can remain ramped down and be paid for that operating under capacity, is really what should have been stated.

Lagassa was not sure how many of his improved sales comparables included only the sale of the facility without attached contracts or transmission lines. He knows some did and knows there were 2 or 3 that stood out as having contracts, he just doesn't know. Lagassa did not adjust his comparables up or down for having a power contract as he considered the benefit of power contract as a security of the knowledge that you have a fixed income, not necessarily a higher income. He agreed that you would then have a reduced risk, but you are getting less money for the reduced risk, which is why he made no adjustment. The subject's sale contained no fixed contracts.

Lagassa stated from 3 to 5 of his comparables sales were regulated utilities and some of the 18 sales were resales of the same properties. Lagassa stated the Bridgeport sale was one that sold more than once and clearly involved Emera, which is a utility in Canada, but was not operating as a utility, so he would not count that among them, but it operated as an independent power producer, so he was not sure. Lagassa admitted that only the Holland Energy plant was the only one in MISO, like the subject. Lagassa admitted that some of his sale comparables were sold as part of a portfolio package and so the sale price was based on an average by dividing the total megawatts. Lagassa stated he was not privy to any particular purchase price allocations of the individual sales. He stated there were some individual sales such as Hector County, a plant he appraised separately. There was also Acadia Power Partners, Block 1; Acadia Power Partners, Block 2; the Hines sale; Hot Springs sale, along with Bridgeport Energy, which sold alone. Lagassa said the Bridgeport Energy sale was interesting because it is about the same size as the subject at 520 megawatts. Lagassa testified that he used sale number 18 to establish the upper boundary and that there is a very convincing argument that it represents a good comparable. Lagassa stated he tried to come up with a single point indicator of value, but could not, so he tried to establish a range and thought that sale number 18 was persuasive and indicated the higher end of the range, so he put a lot of faith into sale number 18.

Lagassa agreed that sale number 18 was his oldest sale in the 2014 report and fell off in the 2015 report. Lagassa stated that from the date of sale number 18 to the date of his report for 2014, gas

prices were at a peak in 2009 and were falling off and continuing to fall off, so the market was effectuated more by declining gas prices and expectation of stable, low prices going forward along with the announcement of more and more shutdowns of coal burning and nuclear plants. Lagassa testified that his five-year average net capacity was 8.9% and included the large jump in 2012 and the low output year. Lagassa agreed that in 2012, the subject plant ran as more of a base load plant. Lagassa admitted that he only had the 2014 and 2015 operating statements because Rockland Capital did not possess them, so he did what he could based on the information provided.

In regard to reconciliation, Lagassa testified all three approaches to value were equally important. Lagassa stated he did not use a market model to forecast in his discounted cash flow analysis because in his experience as an appraiser, they are costly and wrong, so he prefers to use his own judgment. Lagassa stated he provided for insurance expense in his discounted cash flow analysis in the administrative and general expenses, however, it is not stated anywhere in his report. He thought it would certainly be in the estimated cost of operation, at least for replacement cost, put forth by the Energy Information Administration. Lagassa testified that one of the characteristics of a discounted cash flow analysis is that you value each individual year of income and discount each individual year back by however many years it is out into the future. He stated it can be fairly arbitrary and it might be dictated by your methodology how long you posit as a holding period. Lagassa explained that as an example when he is going to value this plant from an income perspective, he is going to suggest they are going to hold this for ten years; and then at the end of the tenth year, the beginning of the eleventh year, they are going to sell it. And what they are going to sell it for at that time is some multiple of what the income has been on the individual years or in the immediate prior year to the sale. So, there is a computation that is applied to compute the revisionary value, which is how much that lump sum would be in the final year, and that computes back into the total net present value of the cash flow.

He stated that one of the differences between direct capitalization and a discounted cash flow analysis is that in direct capitalization, whatever that reversion is out there in that distant future, that is already factored into your capitalization rate. But, when you establish a discount rate, you do not do that, so you have to make a provision for adding it into the last year. Page 67 of his 2015 report states "[o]ur discounted cash flow analysis assumes perpetual asset life due to life extension based on regular capital expenditures and sale of the asset at the end of the posited holding period in 2035." Lagassa testified that if he did not assume perpetual asset life, then in 2035 it would have no value because it would not be sold. It would just be dead. He said it might have salvage value, the land would still be there and that would have value. The machinery could be sold into a scrap market or maybe sold to a Third World nation to be reused or whatever. Lagassa testified that his assumption is fairly typical for a utility property to assume that the asset you are looking at will be there in perpetuity; and, therefore, there is that extra bump of value in the final year.

When asked whether his capital expenditure forecast included sufficient funds to replace the steam turbines and perform major maintenance on a combined cycle combustion turbine, Lagassa testified that since it was based on what was presented to him by Rockland Capital, the early years are fairly large sums and the assumption is that they are investing in order to maintain them and that at the end of 35 or 40 years essentially what you have there is a completely new

project from what was there on year 1 because they are constantly improving it, adding to it and replacing pieces. So, the amount of money which he started out at around $250,000 a year which was discerned from the forecast capital expenditures of Rockland Capital is what he posited there. Lagassa agreed that number seems relatively low, but not necessarily when you pair it up with the larger sums of money that were scheduled in the Rockland Capital forecast. When asked if it was typical to schedule repairs into a budget even though you may not end up spending the money in the year in question, Lagassa responded that he would assume that if you are scheduling the money, then you must think it was necessary. Lagassa agreed that his assumption meant the subject property would be worth $500 million 20 years from now, he stated the terminal value would be $497 million in 2035 dollars with a present-value of that today being $79 million. Lagassa stated that the chronological age of the property in 2035 would be 34 years old if dated back to 2001 and the effective age may be quite a bit less because of the expenditures that will have been made along the way.

Lagassa testified that he assigned a life of 60 years' service life to the coal related assets in his cost approach to value, and for the others he assigned a service life of 35 years. Lagassa stated he used a gross heat rate for the subject property on two different occasions in his report. One was for computing functional obsolescence owing to the increased gas demand of the subject relative to the replacement. He believed that was appropriate in that case because he was measuring the actual utility of the project by comparison to the utility of the replacement. He stated there was no reason to assume that the stated heat rates of the replacement were anything other than gross heat rates, which seemed to make sense. In addition, in the computation of the discounted cash flow analysis, he used gross heat rate, in part, largely because it seemed to him he was measuring the utility of the project and asked how much it costs to operate the plant. He stated the answer is based on the gross heat rate, but it makes sense from the income perspective to apply a net heat rate there upon rethinking. Lagassa testified that he had done that analysis and it does lower the value by the income approach slightly.

When asked if his appraisal was based on a fee simple interest, Lagassa stated it was. In regard to page 9 of his report wherein its states the appraisal of the subject power plant and continued use as a going concern means that in order for it to have value, it is part of a business, essentially, he stated at some level, this was a business valuation, they were looking at the income that is generated by virtue of it selling power into a market and were trying to determine what one would pay for the real assets based on what is available by operating as a going concern, but all three estimated values under all three approaches were fee simple interests. Lagassa described the subject property in his report as being in good condition, well maintained and capable of serving the intended purpose as of January 1, 2014, which he would have to say was operation as an intermediate plant. However, Lagassa admitted that in 2014 the subject property was not operating as an intermediate plant as its nominal capacity factor based on 570-megawatts was 1.7%. Lagassa stated that these percentages seemed low to him for an intermediate plant. Lagassa stated that the Gibson City plants operated at around 1% or 2%, so if you call them peaking plants then the subject corresponds to that, even though they are different in that they are simple cycle plants.

Lagassa explained that he was not concerned about the forced outages at the subject plant because he was looking at actual production which would certainly have taken into account what

the forced outage ratings were. He knew that on average, in certain years it was low and in certain years it was high, but on average the production of 8.9% seemed reasonable. Lagassa agreed that if he had looked further into, it might have indicated whether the forced outages were management related or equipment related, however, he did not look into it.

Lagassa testified that sale comparables number 1, 3, 5, 7, 12, 15 and 16 were portfolio sales with the sale prices shown being the total for all plants involved in each sale. He broke the sales down by opining the capacity of each sale had a value which is discerned by the average value per kilowatt paid. He simply divided the installed capacity by the sales price as a unit of measurement. To verify each sale he used, Lagassa read the press, a variety of magazines that reported the sales such as Power Finance & Risk, standard newspapers, local newspapers and in some cases confirming articles. He did not talk to any brokers about the specific sales he used. Lagassa agreed that the details of each sale may be lacking in the articles he used to confirm the sales and a person would not see that there is reference to there being call options or put options or power purchase agreements, which are seldom available. Lagassa testified that his final conclusion value tried to take into account the value of going concern by establishing a range and discounting what he thought were markets where the price and the implicit price that might be paid under a power purchase agreement would benefit the value. So, he ultimately ended up with a 30% discount for determining the low range. Lagassa agreed the subject sells energy in an unregulated market as do all of the sale comparables he used. Lagassa also agreed there is much less risk in a regulated market and it would affect the discount rates applied, which is a measure of risk. Lagassa testified that a general discount flow analysis is inherently reliable, however, he agreed that if an error is made upfront in one of the estimations, the error is compounded over the projected number of years. Lagassa testified that he forecast electric energy revenues to increase or decrease in line with natural gas. Further, if that assumption is wrong, then his numbers are all wrong all the way throughout. However, maybe for some reason only one of them is wrong, maybe for some reason in one year it did not match natural gas prices, but, he thinks as a general rule, it is a reliable assumption.

Lagassa admitted that he was relying on the price of natural gas being relatively stable throughout the projection period. He believed Annual Energy Outlook was looking at a 3.5% growth rate over a 35-year period. When asked why he used 9.5% if his five-year range came in at 8.9% he stated it was because the market at the end of the five-year period in either 2014 or 2015 was characterized as the expectation that natural gas prices were going to fall going forward and that, as a consequence of that, the natural gas combined cycle plants would be able to compete more effectively against other cheaper sources of power such as coal and nuclear. In addition, with coal being shut down as a result of environmental regulations, he thought it was reasonable to make that assumption. Plus, it helped his analysis because they were able to find some years where they know that when they operate at a 9.4% capacity factor, they had a pretty good sense that that is probably a good measure of what the operating costs would be and so on.

Lagassa stated the Annual Energy Outlook study goes out 35 to 40 years, which he found to be reliable. Further, he stated a lot of corporations, businesses who rely on consumption of energy rely on the Annual Energy Outlook study. Lagassa testified that the Annual Energy Outlook study is quite complicated model with low growth, a reference case which is a prediction based on existing legislation and a high growth scenario. Lagassa testified that he appraised the subject

property as of January 1, 2010 for a property tax appeal along with the appraisals which are the subject matter of these appeals for 2014 and 2015. Lagassa testified that he is a qualified ASA, which is not a license, but is rather a private organization in which he pays dues to. He stated it takes a certain number of years and a certain number of appraisals prepared to prove competence and pass some exams to appraise machinery and equipment. Lagassa agreed that appraising machinery and equipment is different that appraising real estate. However, Lagassa testified that he is also a licensed as a real estate appraiser and in order to maintain that license, he has to take continuing education credits which he finds is applicable and useful to his practice as a machinery and equipment specialist.

During re-direct, Lagassa testified that he has never been disciplined for the contents of an appraisal. He stated his discipline was when he was working for counsel Ginsburg and Lane in the same law firm doing an appraisal of the Collins station, which was a 2,600 or 2,800-megawatt gas fired thermal station in Grundy County. He stated he was called in because the appraiser that had been working on the case for years was dying of cancer. Lagassa elected to do the appraisal, even though he was extremely busy, and in the course of working on that appraisal, he postponed his application for a license in Illinois. Lagassa stated he submitted an application for license and the appraisal was submitted to the Property Tax Appeal Board with the designation of license pending. He explained the attorney on the other side called the licensing board and they made him pay a very large fine because he had not yet received his license even though he had submitted his application. He stated he received a consent decree and as a result he was granted a license. Lagassa testified that there was never any question of ethics or competence, but, he did have to pay a stiff fine in Illinois which they based on his fee. Lagassa stated that to make matters worse, he was also fined $250 by the State of Maine for not informing them, which he was not aware that he had to.

Lagassa testified that a 9.5% capacity factor for a plant that was designed as a base load plant takes into account the inefficiencies and maintenance issues along with other economic factors that may be related to forced outages and other inefficiencies. He stated the 9.5% capacity factor is the reality of the way it has operated on average over the past five years. Lagassa testified that he brought his work file which could be examined to validate the 25.5% economic obsolescence in his report. He stated he did not put the calculations in the report so as not to confuse the reader. He stated the basic intention in the report was to show the logic of his thinking, so he reported where the 25.5% came from and could have put in the computations, but since he did not, he brought along his work file to the hearing, if needed. In regard to extracting out the value of going concern from the value of the real estate, Lagassa testified that he subtracted out the value of the intangibles and goodwill and determined what those were by looking at benchmark companies as reported in FERC Form 1 and found that in the electrical business there was not a whole lot of measurable goodwill. Lagassa does believe there is intangible benefit in the form of labor contracts and there might be some benefit in the form of power contracts and fuel contracts along with a mobilized labor force having value, but those are accounting functions that are actually accounted for in Yahoo Finance and in the FERC Form 1. So, he looked at how much that are accounted for by those comparables and determined that about 1% was a reasonable measure of intangible value and was removed. Lagassa stated that his computation of final value found on page 80 of his report is the value of the property without the intangible portions and the part that would be considered business value. Lagassa testified that the sources he used such as

the Business Wire, a Berkshire Hathaway company, Electric Light and Power, magazines which he receives are read only by people in the industry and are generically called the financial press. Lagassa stated that he is comfortable that the source of information he used provides a reasonable range for his sales comparison approach sufficient enough to be relied upon as an expert in valuing the subject property. Lagassa then admitted that he does not believe everything he reads without verification. Lagassa testified that he verified the information in his sales comparison approach by looking at the press releases from the companies, looking at the press reporting and trying to find at least two or three sources that reported the same information.

Intervenor's counsel then highlighted documents entered into the record. In both the 2014 and 2015 appeals, the intervenor submitted a number of documents from authoritative sources including the U.S. Energy Information Administration, SNL Financial, Reuters, Wall Street Journal, The Brattle Group and the United States Congressional Research Service. Documents "E" through "I" are the EIA documents regarding what was happening in the market for natural gas leading up to the effective date of value. Document "D" is an article of July 6, 2011 from the EIA titled "Natural Gas Use in the Electric Power Sector is Growing" which discuses how since 2005 "the nations fleet of natural gas combined cycle power plants is contributing significantly more to base load electricity needs. Additionally, natural gas combined cycle power plants operate highly efficiently, allowing plants to generate a greater volume of electricity per unit of natural gas burned."

Exhibit No. I is a document from SNL Energy, dated November 1, 2013 entitled "Once Dour, Outlook for U.S. Natural Gas is Making a U-turn." The document states "After two years of low prices, natural gas analysts and members of the industry appear to be increasingly positive about role natural gas will play in the U.S. energy picture" looking at the industry according to Black & Veatch study released October 30th, "People directly involved in the industry also see a bright future for American gas supplies. 95% of the more than 330 respondents and industry stakeholders and representatives throughout the value trade consider themselves optimistic or very optimistic in their outlook on energy growth by 2020, a 3-percentage point increase from the previous year's survey." Counsel stated the last paragraph reads "[t]he respondents in the Black & Veatch survey were not the only ones who saw electric generation as a potential boost demand. National Center for Policy Analysis fellow H. Sterling Burnett told SNL Energy that he believes it will be the unquestioned driver of increased gas demand over the next several years as the Obama administration is going to take care of coal plants through increased regulation."

Exhibit No. J is a document just before the effective date of value dated October 2013, also from SNL Energy, which discussed how the fracking technology has impacted the productivity of natural gas. The article states "Marcellus and Utica natural gas production growth will depress natural gas prices with new pipeline projects driving the production growth amid an absence of demand until 2015 when power sector demand will rise with the implementation of the Mercury and Air Toxics Standards." "Strong Marcellus and Utica Shale gas production is pressuring natural gas price outlooks for 2014 and beyond according to recent reports released by analyst from Goldman Sachs and Morgan Stanley. Morgan Stanley analysts impress weakness in moving forward particularly in 2014, given very large Marcellus/Utica production increases, the equity research team said in an October 16th report." The article then states that "in 2013 SNL

data shows the ongoing efforts to improve transportation of the abundant shale gas resource to areas of demand."

Exhibit No. K is a document dated October 18, 2013 from SNL Energy entitled "EPA Carbon Rule to Remove Last Impediment to Building a Lot of New Gas Plants." Counsel stated this document highlights how the impact of the coal regulations are making gas plants the power source of choice and reads "[i]n fact, greenhouse gas rules provide for new plants as currently written bode well for natural gas demand from power plants, according to Stuart Pearman, partner and energy practice leader for consulting firm Scott Madden, Inc. They assure that no new coal plants will be built, Pearman said. Given the lead times for nuclear, that means that gas is the only game in town for base load replacements." In addition, the article states " [n]atural gas supply abundance in the U.S. and low wholesale gas prices combined with the prospect of low gas prices going forward have given gas-fired generation a tremendous advantage in the marketplace. Since 1990, natural gas has represented 71 percent of generation capacity additions in the U.S., according to Sneed."

Exhibit No. N is a document dated April 12, 2013 published by SNL Financial intitled "Analyst Weak, Shale Production Transforming Face of U.S. Energy Landscape" and reads "[t]his year the Utica shale will race with the Marcellus Shale to increase U.S. oil and natural gas production. Abundant supply will continue to reshape the energy landscape by decreasing prices and increasing competitiveness while spurring infrastructure, growth, and new demand opportunities." Further, "the EIA estimates that the lower 48 natural gas production increase by 15 billion cubic feet per day from 50.8 Bcf per day in January 2007 to 65.8 Bcf per day in December 2012." The document further reads "[h]owever, more infrastructure is needed for gas output to maintain its pace of growth, the Barclay analyst said." Further, the document depicts "as to transportation infrastructure expenditures, they are adding natural gas processing plants and refinery expansions. In the NGL industry alone, over 80 new NGL processing plants are being built and that will add 14.6 billion cubic feet per day of new capacity and require 16 pipeline projects to connect them in production."

Exhibit No. R is a document prepared by financial analysts The Brattle Group and is entitled "Potential Coal Plant Retirements 2012 Update." The document states "[t]he energy market outlook and emerging environmental regulations had changed substantially since we last studied the potential for coal plant retirements in December of 2010. The decrease in spot and forward gas prices combined with low demands of power have caused projected energy margins in the spot of replacement power decrease, altering the economics for coal units toward retirement versus retrofit decisions." The document further reads "[a]s of July 2012, approximately 30 gigawatt of coal plant capacity, roughly ten percent of total coal capacity, had announced plans to retire by 2016. Some of these announcements may be reversed if market conditions improve for coal units, but it appears more likely that many additional units will join the retirement list of the currently foreseen market conditions continue as expected over the next few years." The document also projected coal retirements by the NERC region and states "[a]s shown in Figure 4, NERC regions SERC," which is the region the subject is located, "as well as RFC have the largest shares of retirements. 27 to 30-gigawatts in SERC and 18 to 26-gigawatts in RFC." Counsel stated the SERC region where the subject is located has the most scheduled retirements of any region in the country. Specifically, with MISO, it states, "[w]hile PJM will have the most

retirements in coal capacity, it will be followed by 11 to 16-gigawatts in the MISO region." The document also states on page 7, table 2 "Projected retirements by ISO/RTO Region" and shows that MISO of all the regions in the country has the second most projected coal retirements.

Exhibit No. T is an analysis prepared by the United States Congressional Research Service entitled "Natural Gas in the U.S. Economy, Opportunities for Growth" is dated November 6, 2012 and begins with "Introduction, What to do With all The Natural Gas?" The document states " [t]he relatively rapid expansion of U.S. natural gas resources over the last five years, particularly from shale gas, has been coupled with slower demand growth by natural gas consumers. The result has been low prices not seen for over a decade and, equally important, prices that are projected to stay low for decades." The document continues with "[h]istorically, natural gas prices in the United States have been volatile. From 1995 to 1999, the spot price of natural gas averaged $2.23 per MBTU but increased to an average price of $4.68 per MBTU during the 2000 to 2004 period, an almost 110 percent rise. From 2005 to 2009, the spot price averaged $7.23 per MBTU, hitting a peak of $15.38 MBTU in December 2005. Prices again spiked in July 2008." Further, "[l]ower recent prices and the optimistic expectation concerning domestic supply have led to a view that the United States will have plentiful supplies of natural gas available at low costs well into the future.'

Counsel pointed out that the U.S. natural gas prices from 1990 through 2012, that essentially the average price of gas compares with the subject's capacity factor, wherein there is a direct correlation as the price of gas goes down, the capacity factor goes up, essentially for the life of the subject plant. On page 14, the document states "[a]s discussed earlier in this report, natural gas is expected to increase its share of electricity generating capacity. The broad reasons for this increase begin with the expected increases in natural gas supply along with low gas prices. Also important are the relatively low carbon emissions of gas-fired plants relative to coal-fired plants and the relatively high capital investment cost of coal-fired plants compared to natural gas-fired plants. An additional benefit for the power generating industry related to natural gas-fired plants is flexibility. Natural gas facilities can increase or decrease generation much more efficiently and cheaply than coal-fired plants. Much of the increase in natural gas-fired generation has been from facilities that have been operating below capacity. Lower fuel costs have given these facilities an advantage over other generators. As a result of these advantages, natural gas plants are expected to account for 60 percent of new generating capacity in the United States between 2001 and 2035. . . . Air Pollution Emissions by Combusted Fuel Type: shows that natural gas is cleaner with respect to carbon dioxide, nitrogen oxides, sulfur dioxide, particulates, and mercury when compared with oil or coal. The documents were marked as Group Exhibit No. 7 for the record. The intervenor then rested its case in chief.

In rebuttal, appellant's counsel called Michael E. Green, ASA, as a witness. Green is employed by Filsinger Energy Partners. He holds the accredited Senior Appraiser designation with the American Society of Appraisers in public utilities and is also a licensed general real estate property appraiser with a license in the State of Alabama, New York and Michigan along with a temporary license in the State of Illinois. He has been an independent fee appraiser since college graduation in 1982; 36 years. He has prepared over 100 appraisals of gas-fired generation plants with over 44-gigawatts of owned capacity. He has previously testified as an expert and the review of reports prior to the hearing.

Green completed a review of the appraisal report prepared by George Lagassa on behalf of Grand Tower Energy, LLC., which was marked as appellant's Exhibit No. 2 for the 2014 review report and as appellant's Exhibit No. 3 for the 2015 review report. Other than the comparable sales used by Lagassa in the 2014 and 2015 appraisal reports, his review was primarily the same in his review reports. The intended users of his review report were his client, Grant Tower Energy, and the Property Tax Appeal Board. The purpose of his assignment was to prepare a review appraisal report of Lagassa's report in accordance with Standard 3 of the Uniform Standards of Professional Appraisal Practice, which requires drawing conclusions which are listed in the executive summary and footnote on page 1-1 of his review report. Green received no assistance in preparing his review report. Green testified the scope of his review involved checking Lagassa's report for completeness, accuracy, adequacy, relevance, reasonableness under applicable law regulations and intended user requirements. He stated he specifically checked the report for errors of and fact and theory.

Green investigated operating characteristics of the subject plant from discussions with the client and a review of reports and other information to which they made available to him. Green stated he evaluated projected dispatch at the facility, projected revenues, projected expenses, capital expenditures, discount rate, comparable sales, replacement costs new and depreciation estimates. However, he did not arrive at an independent valuation of the subject facility. Upon completion of his review, Green opined that Lagassa included all three applicable approaches to value, however, each of the approaches contained certain flaws.

Green testified that in the cost approach to value, Lagassa reached an inaccurate conclusion about operating characteristics of a combined cycle plant by comparing them to the same quick-start capabilities of a simple cycle plant. In addition, he used a conventional natural gas-fired combined cycle plant as a replacement cost, which is older technology than is available today. Green testified Lagassa should have used an advanced natural gas combined cycle plant, which were the types of plants being constructed as of the appraisal dates using what is referred to as H-frame technology; which are more efficient. Green stated he had no particular issues with Lagassa's estimate of physical deterioration, which appeared reasonable. However, Lagassa's selection of the heat rate in measuring functional obsolescence, he should have been comparing the facility's net heat rate against the net heat rate of an advanced natural gas combined cycle facility, which would have been roughly 1,000 BTUs per kilowatt hour lower. In regard to the heat rate and referring to the appendix in Lagassa's reports, Green stated there is a document prepared by the Energy Information Administration what was subcontracted out to R.W. Beck, now SAIC, that gives the various operating parameters and efficiencies.

In addition, Green stated Lagassa did not pick up that a modern natural gas plant would run much more frequently than the subject facility because it is more efficient. He stated the way MISO and other ISOs will dispatch power plants is they will array all the plants from the lowest variable cost to the highest variable cost. Green testified that wind farms and solar farms have no fuel costs, so they are the first ones to run, every moment they are available when the wind blows and the sun shines; they are going to run first. The next increment of cost will be the nuclear plants which have a low fuel cost and fairly low variable operating costs; they will be dispatched next. Green testified that back before natural gas prices were as low as they are

today, coal plants would have been the next in the dispatch queue to be dispatched and they would run 24/7 or basically for every hour that they were available. Then, it would be the natural gas plants would be operated as a swing plant and be dispatched at part load.

Green testified that there is confusion in the terminology between base load and what he calls part load. He stated they can run at less than 500-megawatts to as low as 250-megawatts. Then, as the load changes during the day, the plant could be ramped up and ramped down, so it is following the load in the system, which is called intermediate or load following. After that, the plants that come on are typically the simple cycle plants because they have the highest fuel costs and the lowest operating efficiencies.

Green testified that a combined cycle plant with a lower heat rate will have a much higher capacity factor than Grand Tower. As an example, Green stated that an advanced plant has a 6,000-heat rate and the natural gas prices are $3 per million BTUs. If you multiply 6 times 3, it has a fuel cost of $18 per megawatt hour. If Grand Tower's heat rate was 7,000 and given a fuel price of $3, its fuel costs would be $21 per megawatt hour, so it is more expensive in terms of price per megawatt hour. Green stated that plants with the lower fuel cost run more, they are lower in the supply curve. Green testified that this impacts upon how the plants are called into service because if you stack all the plants from lowest costs to the highest costs in terms of capacity and if you have 10,000-megawatts to be dispatched, then you go up the stack and look at which plants can supply the 10,000-megawatt level that can be called upon, what are its fuel costs and that sets the market price at any given moment. Green stated that in periods of high demand in the summer when they are running the simple cycle plants and the fuel costs are really high, assuming an 11,000-heat rate at a $3 price, that is $33 a megawatt hour. This would be the market clearing price. Green explained this is the way the system is both dispatched and sets market prices.

Green testified that in term of Lagassa's cost approach, Lagassa used a perpetuity model which has no place in the analysis because these plants have finite lives and will get retired for either physical or technological reasons. Green testified that these errors have an effect on value. Green stated that some of the data used by Lagassa was both inadequate and irrelevant.

In regard to the market approach developed by Lagassa, Green stated the sales had no description of the technologies involved, so the reader does not know whether they were Westinghouse machines, GE machines, GEEAs or FAs, which have differences that affect performance. In addition he found no discussion of PPAs or of the heat rates. Green stated average heat rates are publicly available from government sources and industry sources. Full load heat rates are a function of technology and with appropriate engineering expertise and input, you can estimate what full load heat rates are for various types of facilities. Further, Green found no discussion in Lagassa's report of market conditions. Green stated the supply and demand balance in any given market area can have a significant impact on value. If the market is tight and in need of additional capacity, prices will be higher. If the market is in surplus capacity, some of which the southeastern market has been in substantial surplus capacity for years, then the values will be depressed. Green found none of this was discussed in Lagassa's report.

Green's review report discusses the sale comparables used by Lagassa and depicts which plants had power purchase agreements associated with them, which plants were located in different geographically diverse markets and how old some of the sales were. Green testified that he prepared an appraisal for sale number 18, the Holland Plant, which was used by Lagassa. Green stated that there was no way he would have used a six-year old sale as a comparable in an appraisal. He stated market conditions in this industry change rapidly and any sale over a year or two could be questionable. Green agreed that the comparables could be adjusted for market conditions, however, the appraiser must have the right information for a market that changes rapidly.

Looking at the income capitalization approach developed by Lagassa, Green testified that he has been concentrating on power plant valuations for approximately 20 years and it has been his practice and experience in dealing with market participants that in every case, a market expert or market model was used to forecast market prices and dispatch. Green testified that there are several commercially available models on the market. Green's company licenses the Aurora model, which lots of market participants use. Green stated it is standard industry practice to project how a plant is going to perform in the future and what kind of revenues it is going to receive. Green said Lagassa did not utilize a model in his forecast estimates in his report. Green testified that Lagassa's report was predicted on a historical average capacity factor and a mystical base price of $45 per megawatt hour for 2013, of which Green has no idea where that number came from. Green testified that he subscribes to a database that has all of the prices set on an hourly basis at the generator node at Grand Tower and the average price per megawatt hour received by Grand Tower in 2013 was $30.72 a megawatt hour, which is $15 a megawatt hour lower than the $45 used by Lagassa. Green testified that this would crush the estimated value.

In regard to the comparable sales approach developed by Lagassa, Green opined that there was no comparable sales analysis or any way to tell that any of the sales were comparable at all to the subject. Green found the comparable sales approach developed by Lagassa was completely unreliable. For example, Green stated Lagassa's sale number 1 included a three-year call option, however the terms of the three-year call option are not disclosed. Green testified that this would affect the value, or the price paid in the transaction, it could be positive, or it could be negative, but that determination cannot be made.

In addition, Green had issues with some of the sale dates. Green did not understand why Lagassa utilized sale no. 4. Further, sale number 5 was a portfolio of contracted cogeneration plants which are in no way comparable to Grand Tower. Green stated most cogens have both power and steam contracts associated with them, which is a totally different physical arraignment.

Looking at sale number 7, Green stated it was a sale of plants spread across the United States, four gas plants from Alabama, California, South Carolina and Virginia. Green found there was no way possible to draw any market value indication from that transaction for the subject facility. Other problems included in Lagassa's report was that he used really old transactions that were listed that have no place in a current market value appraisal because the market changes so rapidly, so they have no relevance to the appraisal. Green found no quantitative support for the

30% adjustment. Green testified that Lagassa's appraisal had severe inadequacies and he would not rely on it. Green testified that he has no interest in the subject property and his fee was not contingent on the value estimate. Green then opined that Lagassa's appraisal report was not reliable.

During cross-examination, Green testified that he reviewed the document provided by Rockland Capital to Lagassa wherein Lagassa calculated a 570-megawatt capacity for the subject. Green found that the calculation by Lagassa was not consistent with what has been reported by the plant to the Federal Government. Looking at page 3-2, the table at the top shows the capacity statistics for nameplate, summer capacity and winter capacity. Green stated that could be downloaded off the internet from the EIA's web site (Form 923). Green testified that combined cycle plants have different capacities based on ambient conditions. In the summertime when the air is hot and less dense, it has a lower maximum capacity than in the wintertime when the air is cold and denser, when it has a higher maximum capacity. Green stated capacity can also be affected by elevation and humidity and various things, but these statistics are reported to the Federal Government. Reading the document, counsel stated the nameplate capacity was depicted as 640.9; summer capacity, 511; and winter capacity, 551; and when averaged, the total average capacity was 567.6. Green did not agree that when there is significant doubt and variation as to a plant's capacity, it would be appropriate to use the information provided by the owner. Green stated the appraiser would have to independently verify the information. Green admitted that installed capacity is a commonly used metric and would be appropriate to use as a basis for comparison. Green was not sure that he used that same metric, installed capacity, in his report. Green then testified that SNL used operating capacity and was shown the document which states, "Total Installed Nameplate Capacity." Green testified that he was not sure the heading on the document was accurate. He stated that if you take the transaction price and divide it by what they call operating capacity, that is the price you get. Green continued to doubt the heading used by SNL.

Green testified that he had issues with the heat rate calculated by Lagassa as being too low because he used an average heat rate, which is different than full load heat rate. Green agreed that in his report, his proposed replacement for the subject is an advanced natural gas plant, not a simple cycle plant. Green testified that if each appraiser, Lagassa and/or Reilly used an average to come up with a capacity factor it would not be the way he would have calculated the estimated capacity. Green stated the price of electricity at $45 per megawatt hour was $15 higher than the actual price paid at the subject node. When pointed out that Reilly used $48.98 for year one, which under counsel's argument would be even more incorrect, Green stated that it contradicts the information he had at his fingertips, he would not have used a historical price to forecast forward. Green agreed that ancillary service revenue is revenue that is appropriately attributed in a discounted cash flow analysis, and it would be incorrect to leave that revenue out, which would bring the value down.

In his report, Green opines that no credible appraiser has ever viewed a combined cycle plant as a perpetual life asset, and if Reilly used the same method as Lagassa, it would be equally incorrect and not credible. Green admitted that he did not visit the subject plant. Green did not find that certain years should be considered or disregarded in the reports when calculating capacities and heat rates because things can fluctuate from year to year based on market conditions, fuel price and other factors. Green agreed that 2002 and 2012 were an anomaly with

extreme fluctuations, however, he would not use that information because he forecasts forward by evaluating what his model said the capacity factors coming out against what history has been to make sure the model is calibrated correctly; he would not use the historical data.

Green explained that the model has a representation of every plant in the market, and that representation includes a full load heat rate and a heat rate curve because a plant is less efficient when it first cranks up, and the higher you ramp it up, the more efficient it becomes, so that heat rate curve starts to flatten out, which is represented in the model. Green testified that they have minimum uptimes and minimum downtimes with hot starts and cold starts. Green said the model tries to reflect all of those things, start costs, minimum run times, ramp rates and how fast it can go from one level to the next. He stated they are very sophisticated market simulation models and are widely used. Green testified that the models are commonly used for integrated resource planning, deal-making, or when a company is trying to figure out whether to build a plant or retire a plant. Green testified that his model would be appropriate for a gas-fired combination turbine unit.

To account for the subject's unique characteristics using old and new equipment, Green testified that he would use the actual operating characteristics, using the higher heat rate, and the full load parameters would be plugged into his model. He would use the subject's actual capabilities of what it has been tested and capable of doing. When questioned on the subject's correct estimated capacity used by each appraiser in the income approach, cost approach and the discounted cash flow analyses, whether 503-megaawatts or 570-megawatts was correct, Green testified that for purposes of comparison, he would use nominal capacity, which is what the capacity is at 59 degrees Fahrenheit. Green testified it is called the ISO rating. Green testified that the trade press will report different capacities which could be summer net or average annual. But, he would show a representation of the subject plant using a column by month depicting 464-megawatts net in the summer without duct firing and then 549-megawatts in the winter and would have a separate column for the duct firing because it has a different characteristic and when it is running without duct firing, it has a lower heat rate, it is inefficient.

Green stated the duct firing is more like a simple cycle plant, if you fire extra gas, you get extra capacity, so he would model the duct firing as a separate plant that gets dispatched separately from the combined cycle plant. Green testified that if he were plugging the information into a spreadsheet, he would use 519 summer and 611 winter and might average the two if he did not know the ISO rating. When he is comparing the subject to other plants, the subject has 60-megawatts of duct firing, so duct firing is cheaper capacity and he would make a physical adjustment. In summary, he would adjust for the duct firing and the capacities would include the duct firing, 519 summer and 611 winter.

Green stated it was not improper for Lagassa to come up with a price per kilowatt in the sales comparison approach to value as it was a standard in the industry and should be looked at when comparing and valuing the subject. Green stated the most important features when selecting comparable properties is age, technology and location because location in different markets affect price levels. Green explained that the cost of natural gas varies by location as the cost of natural gas in Pennsylvania is cheaper than on the Gulf coast because it is sitting on the Marcellus shale. Green testified that the most appropriate method to value the subject property is

the discounted cash flow analysis because it is the only method that allows you to take into consideration all of the characteristics of the subject property.

Green's had problems with Lagassa's discounted cash flow analysis because of his reversionary value and the lack of a sophisticated forecast. Green does not have a problem with the discount rates Lagassa used, but he thought the revenue forecast was over simplistic and not reliable in his opinion. Green testified the subject has functioned in the peaking range, however, it is designed to run at full load. He stated base load means, in the conventional sense, how much it runs over a year's time, with the exception being wind turbine, the non-fuel ones. Wind is going to run base load even though its capacity factor is miserable, 25%, but it is going to run every time the wind blows. Same with solar and running river hydro, they are base load plants. They have low capacity factors, but they are base load plants. They are designed to run first, that is base load. Green did not know where the subject would land, but, historically it is run as a peaking plant, so in this market it appears to fit there.

On redirect, Green testified that there is no relevancy to 567-megawatt capacity counsel had him compute. Green stated he doubted SNL because he has used SNL for about three years and it could be the terminology, so you have to look at what their definitions are for a specific number, like their definition of operating capacity and summer capacity, winter capacity. You need to look further where they got their numbers and how they used them. Green testified that there is an inverse correlation between price and capacity factor. There is 8,760 hours in a year, and every price is different. If you put them in a spreadsheet and sort from highest to lowest price, you can create what is called a price duration curve. Green stated the top 10% of the average price of that curve is going to be a high number. He stated on peak is about 47% of the top end of the curve, so the average price for on peak is going to be lower. But, fundamentally speaking, the lower the capacity factor, the higher the average energy price received. He said base load plants get the lowest average energy price because they are running 24/7 and they are getting the average of the high and low prices, while the peakers are only capturing those highest prices.

During re-cross examination, Green testified that in the sales comparison approach to value he would have adjusted for fuel efficiency for differences between a simple cycle plant and a natural gas combined cycle plant. Green admitted that the appraisal of this plant is particularly difficult because it has very high forced outage rates and the fact it is using old steam turbines. Green stated the sophisticated models he talked about earlier would cost between $50,000 and $75,000.

The Notice of Final Decision of the Jackson County Board of Review for 2014 and evidence of the subject's 2015 assessment depicts assessment values for the subject parcels under appeal as follows:

2014

DOCKET NO	PARCEL NUMBER	LAND	IMPRVMT	TOTAL
14-03445.001-I-3	16-13-100-001	9,970	0	$9,970
14-03445.002-I-3	16-13-300-001	1,909	0	$1,909
14-03445.003-I-3	16-13-300-004	1,338	0	$1,338

14-03445.004-I-3	16-13-300-006	152,052	0	$152,052
14-03445.005-I-3	16-14-200-001	115,807	31,254,127	$31,369,934
14-03445.006-I-3	16-14-200-002	601	0	$601
14-03445.007-I-3	16-14-400-002	1,396	0	$1,396
14-03445.008-I-3	16-23-200-001	766	0	$766
14-03445.009-I-3	16-24-101-001	509	0	$509

2015[10]

DOCKET NO	PARCEL NUMBER	LAND	IMPRVMT	TOTAL
15-00452.001-I-3	16-13-100-001	9,740	0	$9,740
15-00452.002-I-3	16-13-300-001	1,909	0	$1,909
15-00452.003-I-3	16-13-300-004	1,338	0	$1,338
15-00452.004-I-3	16-13-300-006	152,052	0	$152,052
15-00452.005-I-3	16-14-200-001	115,807	31,254,127	$31,369,934
15-00452.006-I-3	16-14-200-002	601	0	$601
15-00452.007-I-3	16-14-400-002	1,396	0	$1,396
15-00452.008-I-3	16-23-200-001	766	0	$766
15-00452.009-I-3	16-24-101-001	509	0	$509
15-00452.010-I-3	46-13-300-001	633	0	$633

For 2014 the subject parcels under appeal had a total assessment of $31,538,475, which reflects a market value of approximately $94,995,407 for 2014 using the three-year average median level of assessments for Jackson County of 33.20%.[11]

For 2015 the subject parcels under appeal had a total assessment of $31,538,878, which reflects a market value of approximately $95,341,277 for 2015 using the three-year average median level of assessments for Jackson County of 33.08%.[12]

Conclusion of Law

After hearing the testimony and considering the evidence, the Property Tax Appeal Board finds that it has jurisdiction over the parties and the subject matter of the appeal. The Board further finds a preponderance of the evidence in this record support a reduction in the subject's assessments.

The appellant contends overvaluation as the basis of the appeal. When market value is the basis of the appeal the value of the property must be proved by a preponderance of the evidence. National City Bank of Michigan/Illinois v. Illinois Property Tax Appeal Board, 331 Ill.App.3d 1038 (3rd Dist. 2002). The Board further finds the best evidence of the subject's market value in this record is the appraisal, prepared by Kevin S. Reilly, ASA, with an opinion of value of

[10] The 2015 appeal contains an additional parcel number, Pin 46-13-300-001, which was not appealed in tax year 2014.
[11] The Jackson County Board of Review submitted no evidence in support of the subject's 2014 assessment.
[12] The Jackson County Board of Review was defaulted in the 2015 appeal by letter dated November 4, 2016.

$20,000,000 as of January 1, 2014 with no significant change in value as of January 1, 2015. The Board finds the appellant met this burden of proof and a reduction in the subject's assessment for 2014 and 2015 is warranted.

Reilly developed the cost, income and a sales comparison approaches to value in estimating the subject property had a market value of $20,000,000 as of January 1, 2014.[13] Reilly's testimony at hearing herein depicts the subject's value as of January 1, 2015 was substantially the same. (Transcript, page 252)

In preparation of their appraisal reports the Board finds Reilly inspected the subject plant in August 2015, while Lagassa relied upon a prior inspection of the subject plant which occurred in November 2012, over one year prior to the valuation date of January 1, 2014. Reilly opined the subject's highest and best use as of January 1, 2014 of the subject facility was its current use as a peaking gas-fired power generation facility selling power into the MISO-Illinois market. (Appellant Exhibit No. 1, page 26) Lagassa opined the subject's highest and best use is as improved for natural gas combined cycle power generation. (Intervenor's Exhibit No. 5, page 40)

Each appraisal report prepared by Lagassa, both the 2014 appraisal and the 2015 appraisal, are reliant on and subject to the hypothetical condition that the necessary repairs to the transition piece on unit one was repaired by January 1, 2014. Lagassa indicated that if it had not been repaired, it could affect his opinion of value. (See Intervenor Exhibit No. 5, page 6) The Board finds this statement is the result of not inspecting the subject property immediately prior to preparation of each report and/or a lack verification at the time of preparing each report.

One of the issues in this appeal involves operation of the plant as a base load, intermediate or peaker plant. The record depicts that historically the subject plant was operating as a peaker plant as of the valuation dates in question and is limited in how it operates based on it being dispatched as such in the MISO-Illinois market. The Board finds Lagassa failed to determine the subject's highest and best use as improved in relation to its utility as a base load, intermediate load or peaker plant in the market in which it operates. The reader of Lagassa's report is left to determine if the subject's highest and best use is as a base load, intermediate load or peaker plant within the MISO-Illinois market.

Under the cost approach to value, Reilly utilized five land sales to estimate the subject's site value. The land comparables were located in either Grand Tower or Fountain Bluff, Illinois. The comparables ranged from 157.78-acres to 311.58-acres and sold from March 2013 to January 2014 for prices ranging from $6,225 to $11,725 per acre. Reilly adjusted the comparables for conditions of sale, location, frontage/access, topography/shape and easements. Reilly opined no adjustments were required for size or utilities. Based on the data, Reilly estimated the subject site had a value of $7,100 per acre for a total land value of $2,388,000, rounded. (See Appellant's Exhibit No. 1, page 30) Lagassa did not prepare a land sales

[13] The appellant relied upon the valuation date of January 1, 2014 found in the Reilly appraisal (Appellant's Exhibit No. 1), as evidence of the subject's valuation as of January 1, 2015. A separate appraisal for 2015 was not submitted into the record.

comparison analysis but was instructed to accept as valid the implicit market value of the subject's land, based on the property tax assessment in Jackson County as of the valuation date. Lagassa, using this data, indicated the subject's total market value of the land of $852,000, rounded. (Intervenor's Exhibit No. 5, page 42) The Board finds Reilly made logical and proper adjustments to the land sale comparables to estimate the subject's land value of $2,388,000, whereas Lagassa simply applied a land value taken from the subject's 2014 assessment, which was based on the subject's previous year stipulated assessment between the board of review, intervenor and the prior owner to support his land value, (see stipulation No. 1). The Board further finds Reilly presented clear and concise evidence within his appraisal report the data and adjustments regarding each sale. Lagassa, on the other hand, presented no testimony or evidence within his appraisal report to support or substantiate his estimated land value for the subject. Based on the testimony herein and on the validity of the evidence presented, the Board finds Reilly's estimate of the subject's land value was more credible.[14]

Reilly developed the replacement cost new of the improvements and explained that the replacement cost new does not represent costs associated with erecting an identical replica of the subject but rather is equal to the cost of a new modern facility with equal utility as the subject. (Appellant's Exhibit No. 1, page 59) Utilizing the Federal Publication Annual Energy Outlook 2014 capital costs dollar-per-kilowatt data to calculate the base replacement cost new for the subject, Reilly added interest during construction and derived a replacement cost new as of January 1, 2014 for the subject of $388,000,000. Reilly then deducted physical deterioration to account for age, wear and tear, corrosion, or fatigue at the subject. In considering the physical condition of the subject, Reilly included an age/life analysis and relied on a visual inspection of the condition of the subject during his site visit, as well as discussions with onsite management, maintenance and engineering personnel. Reilly used the age/life relationship to look at the age of the subject's assets and then looked at the average service life and expected life of the assets to arrive at a ratio. Other than the new major assets such as the combustion turbine, steam turbine generators and heat recovery steam generators, Reilly capped the older equipment at 65% of physical deterioration. The total electrical generating assets were determined to have physical deterioration of 44%. Overall, the analysis resulted in an overall physical deterioration for the subject of 50% with a remaining physical life of 18 years. (Appellant's Exhibit No. 1, page 66) Reilly then applied the 50% physical deterioration to the replacement cost new ($388,000,000 x 50%) and deducted 50% ($194,000,000) to arrive at a replacement cost new less physical deterioration of $194,000,000. Reilly then compared the subject's historical non-fuel operating costs to the fixed and variable operating expenses of a modern replacement plant as published in the 2014 Annual Energy Outlook. Reilly then examined the cost of fuel as an operating expense which resulted in a negative $1,913,277 of functional obsolescence. (Appellant's Exhibit No. 1, page 70) Reilly calculated economic obsolescence by utilizing an earnings shortfall method by looking at the cost of a brand-new plant without physical and functional obsolescence and running a cash flow scenario for that plant which he then present-valued that cash flow back to a value today. Reilly testified that if it was equal or greater than the cost to build the facility, then that indicated no economic obsolescence. If it was less, then economic obsolescence existed. Reilly's analysis indicated a significant level of economic obsolescence of 94% from return

[14] The discussion on the issue of land value goes to the weight ascribed to the credibility of each appraisal as the land values for the subject parcels under appeal were stipulated to prior to hearing.

shortfall and concluded 90% of economic obsolescence existed. Reilly then examined the subject's budget for expenses. He examined capital expenditures ("CAPEX"). Reilly testified that in regard to the regulatory mandates the subject is exposed to, such as the ash pond, which a new gas-fired plant would not have, and the required retrofits, upgrades, maintenance and capital expenses to comply with regulation 316(b), he was looking at expenses as if someone were coming in to buy Grand Tower and had to comply with the regulations. Reilly then calculated present-value as of January 1, 2014 to arrive at necessary capital expenditures of $9,862,631. Reilly then used his estimated replacement cost new of $388,000,000, subtracted 50% physical deterioration of $194,000,000 along with functional and economic obsolescence of 90% and necessary capital expenditures of $9,900,000 which indicated a value of the improvements of $11,400,000 to which he added a land value of $2,388,000 to derive a value for the subject under the cost approach to value of $14,000,000. (Appellant's Exhibit No. 1, page 75)

Lagassa also developed a replacement cost new analysis by differentiating between the value of land and the value of the improvements, then determining a replacement cost of the improvements and the extent of depreciation which are subtracted to come up with a replacement cost new.

In developing his cost approach to value, one of the pieces of information he requested from the owners was a fixed asset ledger which would indicate the original cost at the time and vintage age of the various remaining surviving assets there. Lagassa applied the Handy-Whitman Index of Public Utility Construction Costs to a fixed asset ledger to determine the reproduction cost as of January 1, 2014 of the old steam turbines together with the newer combustion turbines, heat recovery steam generators and of all the ancillary equipment that had not been retired to arrive at a replacement cost new of $748,503,146. (Intervenor's Exhibit No. 5, page 46) Lagassa's replacement cost analysis was based on the published data from the Annual Energy Outlook for 2013 where price per installed kilowatt for a conventional natural gas combined cycle facility was stated at $901 as an overnight cost. After all adjustments, Lagassa concluded the cost per installed kilowatt of a conventional combined cycle of 570-megawatts would be $1,004 per kilowatt, which amounts to $572,280,000. He then added interest during construction which he calculated assuming a three-year construction period and interest at prime plus 100 base points which seemed reasonable. He then added in the value of the land ($852,000) to arrive at a total cost to replacement of $618,084,000 as of January 1, 2014. In order to calculate incurable physical deterioration Lagassa used the age-life method refined by determining an effective age based on a dollar weighted replacement cost versus an actual replacement cost. Lagassa determined 55.3% of physical depreciation as of January 1, 2014 was appropriate. Lagassa found functional obsolescence based on the loss in value as a result of the development of new technology. He testified that one form of functional obsolescence was excess construction which is measured by the difference between the reproduction cost new less the cost of replacement with a second form of functional obsolescence because of the more efficient operation of the replacement which had a stated heat rate of 7,050 BTU as opposed to a heat rate that he adopted of approximately 7,500 BTU. Lagassa explained the difference meant that the operation of the replacement facility would be more efficient than the operation of the subject by that 450 BTU difference in the heat rate. Lagassa then analyzed how much fuel would be consumed over a holding period going forward and determined that the present-value of the additional operating costs associated with the subject relative to the lower heat rate of the comparable was

$15,191,000. In addition, Lagassa computed for two forms of external obsolescence. One for being the obsolescence imposed on a facility by virtue of events that occur outside of the asset itself and determined a net present-value of $5,609,000 needed to be subtracted for external obsolescence.

Lagassa also did a comparison of the subject facility to the operation of the replacement less physical depreciation to determine how much additional income would be required in order to make it possible to justify the expense invested in the subject plant. He determined that the difference would require an additional 25.5% of income year after year after year in order to justify that expenditure. So, Lagassa deducted 25.5% from the balance to determine a total amount of economic obsolescence (see page 49, intervenor's Exhibit No. 5). Lagassa found the excess construction which was the difference between reproduction cost new and the cost to replacement was $131,271,000, which was subtracted. Physical deterioration was subtracted from the cost to replacement at 55.3%, resulting in a balance of $275,902,000. He then subtracted 25.5% of that for the revenue deficiency associated with the increased cost of operation of the comparable and then also subtracted functional obsolescence and external obsolescence, re-added the value of the land and came up with a replacement cost new value less deprecation of $185,600,000 as of January 1, 2014.

During cross-examination, Lagassa admitted that in his report he does not tell the reader how he arrived at his 25% economic obsolescence and does not show the computation, but, he essentially determined that the cost of replacement less physical depreciation of a conventional natural gas combine cycle plant would be $275,902,700 and that the annual income would need to be increased by 25.5%. Lagassa stated that to get to the 25%, he played around with the percentage, raising it, raising it, raising it and lowering it until the total net present-value of the income amounted to $275,902,700. Green testified that Lagassa erred in his cost approach to value and reached an inaccurate conclusion about the operating characteristics of a combined cycle plant by comparing them to the same quick-start capabilities of a simple cycle plant. In addition, he used a conventional natural gas-fired combined cycle plant as a replacement cost, which is older technology than is available today. Green testified Lagassa should have used an advanced natural gas combined cycle plant, which were the types of plants being constructed as of the appraisal dates using what is referred to as H-frame technology; which are more efficient. Green stated he had no particular issues with Lagassa's estimate of physical deterioration, which appeared reasonable. However, Lagassa's selection of the heat rate in measuring functional obsolescence was incorrect when he should have been comparing the facility's net heat rate against the net heat rate of an advanced natural gas combined cycle facility, which would have been roughly 1,000 BTUs per kilowatt hour lower. In regard to the heat rate and referring to the appendix in Lagassa's reports, Green stated there is a document prepared by the Energy Information Administration that gives the various operating parameters and efficiencies. In addition, Green stated Lagassa did not pick up that a modern natural gas plant would run much more frequently than the subject facility because it is more efficient.

The Board gives less weight to Lagassa's cost approach analysis based on the testimony and evidence produced herein. As counsel pointed out, Lagassa erred in his characterization of the operating characteristics of a natural gas-fired combined cycle plant as offering the quick start capability of a peaking plant. The Board finds this contradicts the historical operation of the

subject plant. As Reilly testified, and it was unrefuted herein, peaking plants typically take from 20 to 30-minutes to start up from a cold start to reach full load. (Transcript, page 112) In contrast, the evidence herein indicates the subject takes 7 to 8-hours to reach full load from a cold start. Even Wells, a former employ at the subject plant, admitted, that from a cold start, the subject takes seven to eight hours to come online. Wells stated that anytime the plant is offline for 72 hours or more, it's going to be a cold start. A warm start would be a re-start from 48 hours to 72 hours of shut down, which would require a 3 to 4-hour start-up time. A hot start would be only about two hours or two and one-half hours after being offline for less than 48 hours.

In addition, as Green pointed out, Lagassa erred in using an incorrect heat rate in the measurement of functional obsolescence stating Lagassa should have compared net the heat rate of an advanced natural gas combined cycle facility, which is approximately 1,000 BTUs per kilowatt hour lower as referenced by the Energy Information Administration and found in the appendix of Lagassa's report. Further, Lagassa failed to include support within his appraisal report for the 25.5% economic calculation. Lagassa testified that he brought his work file to the hearing which could be examined to validate the 25.5% economic obsolescence in his report. Lagassa stated that to get to the 25%, he played around with the percentage until he reached a desired amount. The Board finds that the amount of economic obsolescence found within the Lagassa report is not well supported.

Based on the testimony herein and the evidence presented, the Board find Reilly's cost approach to value was better supported within the appraisal report and is more credible. The Board further finds that even though all experts agreed that a discounted cash flow analysis is the proper method to be used in valuation of the subject property, errors in the proper development of a cost approach analysis detracts from the final opinion of value and discredits the validity of the overall report.

Both appraisers developed a sales comparison approach to value. Reilly utilized six sales of combustion turbine plants located in South Carolina, Ohio, Utah and Tennessee. Reilly explained in his appraisal report the sales were selected based on their similar operation of the subject. Reilly further narrowed his selection of sales based on operation in unregulated markets. The sale comparables were built from 1996 to 2003 and had operating capacities ranging from 205-megawatts to 900.08-megawatts. The sales occurred from 2007 to 2012 and sold for prices ranging from $55,000,000 to $427,000,000 or from $91 per kilowatt to $403 per kilowatt. Reilly then adjusted the sales to the subject for operating capacity, chronological age, location and time/market conditions. The sale comparables had adjusted sales prices per kilowatt ranging from $40 per kilowatt to $290 per kilowatt. Reilly determined comparable sale number 2 was most similar to the subject, with an equal chronological age and similar capacity. However, he found sale number 2 was located in the PJM-ISO market, which he explained is more robust and has a well-defined capacity market with a future capacity auction.

Reilly further explained in his appraisal that because of the lack of market information, an adjustment, even though superior, could not be made for the capacity market. Reilly stated Grand Tower is unique as a hybrid plant with steam turbines designed for coal use with buildings and structures built in the 1920s. As a result, this did not allow Grand Tower to ramp up and

down as quickly as the combustion turbine comparables. Reilly indicated Grand Tower's revenues would be less than that of the comparables he used, indicating Grand Tower was inferior to the comparables. From this, Reilly concluded his sales comparison approach to value indicated a value for the subject of $70 per kilowatt or $35,210,000 using an estimated capacity for the subject of 503 kilowatts. Reilly concluded in his appraisal report that while the sales comparison approach to value was fully developed, its conclusion was considered less reliable than the cost and income approaches to value, and therefore, minimum weight was given to the sales comparison approach to value in his final conclusion of fair cash value for the subject.

Lagassa also developed a sales comparison approach to value using 18 sales in the 2014 appraisal and 12 sales in the 2015 appraisal. Lagassa's 18 sales in his 2014 report were located primarily in Texas, Connecticut, Rhode Island, Maine, California, Alabama, South Carolina, Virginia, Louisiana, Massachusetts, and Illinois. The comparables sold from January 2009 to December 2013 for prices ranging from $136,000,000 to $1,050,000,000 or from $332 per kilowatt to $1,016 per kilowatt. The 12 comparable sales in his 2015 report were primarily located in Massachusetts, Oklahoma, Alabama, Florida, South Carolina, Texas, Connecticut, Rhode Island, Maine, California and Virginia. All of Lagassa's sales involved combined cycle natural gas facilities. The 2015 report depicts the comparables sold from January 2011 to November 2014 for prices ranging from $136,000,000 to $1,557,000,000 or from $336 per kilowatt to $1,016 per kilowatt. His 2014 sales ranged from $332 per kilowatt of installed capacity to $829 per kilowatt of installed capacity. Lagassa found eight of the sales produced an average $467 per kilowatt of installed capacity, which he then assumed a 30% negative adjustment to arrive at a high-end average of $327 per kilowatt of installed capacity, He then found the remaining sales supported an average price paid of $477 per kilowatt.[15] Finally, Lagassa examined sale number 18 with an indicated price of $608 per kilowatt of capacity which he applied a negative adjustment to arrive at an indicated value of $480 per kilowatt of installed capacity. From this Lagassa concluded a range of estimated value as of January 1, 2014 for the subject property of between $186,390,000 and $271,890,000 and as of January 1, 2015 of between $191,520,000 and $221,160,000. Lagassa basically applied the same methodology to his sales comparables in his 2015 report wherein he found the sales price of natural gas combustion facilities ranged from $336 per kilowatt to $683 per kilowatt with an average price paid of $499 per kilowatt. After again applying a 30% downward adjustment to eight of the sales, Lagassa concluded a range of $336 per kilowatt to $388 per kilowatt or an estimated value range for the subject property of between $191,520,000 and $221,160,000 as of January 21 , 2015.

The Board agrees with the testimony of Green that Lagassa's report offers only a limited analysis of the properties sold and does not properly account for the similarities and differences between the subject property and the sale comparables. (see Filsinger Energy Appraisal Report, Section 4.4.3) Lagassa failed to provide a description of the technologies of each comparable sale and did not further discuss the capacity factor for each sale, heat rate or conditions of the market wherein each sale comparable was located. The Board is left to assume the applied adjustments appear correct without detailed examinations as to the reasons therefore. Green's review report

[15] The averages were computed by dividing the total price of all comparables sales included by the total capacity of the comparables. (See Intervenor's Exhibit No. 5, page 56)

depicts Lagassa's sales comparables included many plants operating under contracts and not as merchant facilities, which may greatly affect the value of each sale. Further, the evidence depicts sale number 2 in the 2014 report with a sale date of December 2013, was also used in the 2015 report, but contained a different sale date of March 2014. Further, sale number 4 was included in the 2014 appraisal report but was then excluded from consideration. (Intervenor Exhibit No. 5, page 52) Many of Lagassa's comparable sales involved portfolio transactions from different markets with fixed contracts in place to sell energy. Lagassa admits in his appraisal report that "there was simply insufficient information about any of these sales to permit reliable and measured paired sales comparison . . . ." (see Intervenor Exhibit No. 5, page 76)

The Board finds the testimony herein reveals an analysis under the sales comparison approach to value for the subject property is difficult at best given the complexities of each sale and lack of information regarding each sale. Many of the sales are located in different power generation markets, involve complex contracts, power purchase agreements and/or contain technologies completely different than that of the subject property. The Board finds each sale contains its own complexity based on the market in which it is located, the technology used, capacity factors, heat rates and additional amenities involved in each sale such as power purchase agreements, contracts and tax incentives. In addition, information from each sale in many cases, can only be verified from public indices and newspapers, not verified with owner/operators and/or brokers.

Based on the testimony and evidence herein, the Board finds Reilly's sales comparison approach, in which he gave minimal weight in his final reconciliation analysis, is better supported. On the other hand, Lagassa, after giving equal weight in his final reconciliation analysis to the sales comparison approach, reiterated in his report that his sales comparison approach was unreliable based on insufficient information regarding each sale. The Board finds it questionable to give equal weight to a developed approach to value that is deemed an unreliable indicator of value.

The next approach developed by each appraiser was the income approach to value. The Board finds all experts in this appeal testified that a discounted cash flow was the best method as an indicator of value for the subject and is one most generally relied upon by investors, owners and buyers involved in the transactions of selling, buying and building generation facilities.

The evidence depicts two basic methodologies can be employed in the income approach to determine fair cash value: a direct capitalization and a discounted cash flow analysis. A direct capitalization method "capitalizes a projected net income or cash flow (expected future benefits) into perpetuity and assumes no variation in the capitalization rate and no termination of the income stream.[16] The discounted cash flow method is an analysis in which the quantity, variability, timing and duration of a periodic income and the residual value are projected, and the periodic income and residual value are then discounted to present-value using a discount rate.[17] The result obtained from a direct capitalization or a discounted cash flow analysis is an indication of the fair cash value of the income producing property's operating business, or

[16] American society of Appraisers, Valuing Machinery and Equipment: The Fundamentals of Appraising Machinery and Technical Assets (3rd Edition, 2011, e-book), 137.
[17] Ibid.

business enterprise value. A business enterprise value includes all tangible assets (property, plant, equipment and working capital) and intangible assets of a continuing business.[18]

Reilly developed both a direct capitalization analysis and a discounted cash flow analysis to determine the subject's fair market value. Reilly's report depicts both analyses measure a potential investor's expectations of future returns and associated risk for the subject facility operating as a gas-fired power generation facility with the merchant power generation industry. In the discounted cash flow analysis, the future operations and free cash flows of the subject facility were developed by projecting revenues for power generation and capacity payments, fuel costs, operating expenses, required capital expenditures and changes to required capital levels. The free cash flows were then discounted using a market-based discount rate to reflect the inherent risk in owning the subject facility.

The direct capitalization analysis was developed similarly, however, it capitalized only year one projections. (Appellant's Exhibit No. 1, page 38) In order to develop the subject's power generation revenues, Reilly examined the subject's historical operations from 2008 to 2013. Reilly found that the subject's 2012 net generation were the highest over the six-year historical period analyzed. Further, he found that in 2008, the subject's net generation were the lowest of the six-year period analyzed. The remaining years had net generation and capacity factors that he found were fairly consistent. Based on this data, Reilly used the average of the six-year historical operations (5% capacity factor), excluding year 2012 to represent the subject's operating as a peaking power generation facility into the future. The record herein depicts year 2012 was an unusually hot summer and was considered an anomaly. Utilizing the last five years of the historical operations, (years 2009 through 2013) indicated a five-year average heat rate of 8,488 Btu/kWh as being reasonable. Reilly then used energy price projections as projected by Ventyx Power Reference Case, Electricity and Fuel Price Outlook, Midwest, Fall 2013 and EIA's Annual Energy Outlook 2014 Early Release. Both of these projected forecasts forward curves for energy prices and for each projected year to provide a reasonable energy forecast trend and forward curve. The projected energy price in a given year was then multiplied by the concluded net generation of 220,314 megawatt hours. In year one projections, the energy price developed for the subject was $48.98 per megawatt hour to indicated year one energy revenue of $10,790,980 (energy price x net generation = $48.98/MWh x 220,314 MWh = $10,790,980).

Reilly then examined the subject's capacity payments as a form of revenue stream for the subject property. Capacity payments are a form of revenue stream that a power generator receives from an ISO or RTO for existing as a potential power generator in a specific market. They represent compensation for a facility's potential net power generation capacity, or the power it can provide at some point in the future. Capacity payments are based on the kW capacity of the facility over a year. Reilly's report depicts capacity payment prices for the MISO-Illinois market were based on discussions between Grand Tower Energy Center, LLC and an independent energy marketer just prior to the valuation date. Reilly's report further depicts that in 2014, a price of $4.20 per kW-year could be expected, increasing to $24.00 per kW-year by 2019. Capacity price that a plant receives is only applied to the available capacity of the plant taking into account typical forced outage rates. Based on discussions with plant personnel, the data indicated the subject

[18] Ibid.

had forced outage rates of 60% on units 1 and 3, and outage rates of approximately 10% on units 2 and 4 as of the appraisal date. Reilly then determined that an investor would improve the outage rates of units 1 and 3 with additional capital expenditures to get them to a more normal rate of 10%. Therefore, he decreased the forced outage rates on units 1 and 3 by 7.50% annually, until the three-year rolling average reached a normal level of 10% in year 10 of the discounted cash flow analysis. Reilly applied the subject's available capacity of 327,000 kW and multiplied this to the capacity price of $4.20 per kW-year to arrive at a capacity revenue of $1,373,400.

Reilly then analyzed the cost of natural gas used by the subject facility to operate using Ventyx Power Reference Case and the Chain-type Price Index as published in the EIA in Annual Energy Outlook 2014 Early Release. Reilly determined the subject's annual fuel consumed by multiplying the net generation by the heat rate and dividing it by 1,000 to convert it to 220,314,000 kwh which he then multiplied by a heat rate of 8,488 Btu/kWh and divided that by $1 million to arrive at an annual fuel in dollars per million Btu of $1,870,025. He then multiplied that by the price of natural gas of $4.22 to arrive at an annual cost of fuel of $7,891,506. Gross margin, which is the result of total revenue from power generation and capacity payments less the cost of fuel consumed was calculated by adding power generation revenue with capacity payments less the cost of fuel ($10,790,980 + $1,373,400 - $7,891,506) which indicated a gross margin of $4,272,874. Reilly then estimated the subject's fixed and variable operating expenses from an analysis of the historical operations of the subject facility as published in FERC Form 1. Reilly estimated $5,215,944 for year one operating expenses and did not include property taxes to which he applied a 20-year modified asset cost recovery system for the machinery and equipment associated with the subject along with a 15-year straight line schedule applied to the intangible asset value which resulted in total operating expenses for year one of $6,431,271.

Reilly's report explains that operating income before interest and taxes ("EBIT") is the result of revenues less the cost of fuel less operating expense, which resulted in EBIT of $2,158,397. In year one of the discounted cash flow analysis income taxes were calculated to be a negative $889,260 to which he added the projected net income for the subject which indicated a negative $1,269,137. CAPEX or projected capital expenditures which account for periodic investments that need to be made at the subject facility for year 1 were $11,226,893. He then calculated free cash flow by adding the net income, depreciation less CAPEX and working capital changes to arrive at $11,280,703. This same method was then developed for years 2 through 10 in the discounted cash flow analysis.

Reilly's report further explains that the future free cash flows that are developed must be discounted to the appraisal date to account for the time value of money and the basic concept that a dollar received today is worth more than a dollar received at some point in the future. The applied discount rate must account for the risk associated with receiving cash flows in the future and also takes into account an investor's required return bearing the risk associated with the investment. Looking at four different capital structures, Reilly concluded long term working capital of 10% was reasonable and reflective of a typical natural gas-fired merchant power generation industry and the subject facility as of January 1, 2014. Using the capital asset pricing model and a buildup method, Reilly concluded a reasonable cost of equity for the subject to be 19.40%. Reilly then concluded a discount rate of 9.90% after adding in the after-tax effective

property tax rate which resulted in a final property tax adjusted after-tax discount rate of 11.40% to be applied in the after-tax discounted cash flow in his discounted cash flow analysis. On the basis of his income approach analysis, Reilly concluded that as of January 1, 2014, the fair cash value of the real and personal property of the subject was $19,692,639 or $20,000,000, rounded (see Appellant's Exhibit No. 1, page 56).

Reilly also developed an addition direct capitalization in his income approach to value. Using his year 1 projections developed earlier in his discounted cash flow analysis, Reilly concluded that the capacity revenue along with capital expenditures were not indicative of expected long term results and were therefore changed to better represent normal operations. Reilly expected that the capacity price in the MISO-Illinois market would increase substantially in the years subsequent to January 1, 2014 and thus he used a stabilized capacity price of $12.54 per kW-year or the 5-year average of year 1 through year 5 which indicated capacity revenue of $6,308,344. Reilly then utilized an average CAPEX of $3,000,000 per year in the direct capitalization analysis to represent normal CAPEX into perpetuity. Discounting the free cash flows using the property tax adjusted after-tax discount rate less cash flow growth of 9.40%, Reilly concluded a direct capitalization analysis indicated a fair cash value for the subject as of January 1, 2014 for the real and personal property of the subject was $20,763,473 or $21,000,000, rounded (see Appellant's Exhibit No. 1, page 58).

In defense of his developed income approach to value, Reilly explained that he used the subject's net capacity rather than gross capacity because net capacity is what a plant can sell and is an amount government agencies rely on. On the other hand, gross capacity includes a parasitic load which is energy used to generate electricity which is not sellable into the market. Reilly also explained that he did not include duct firing capacity because the duct burners were not operational as of January 1, 2014. Intervenor relied upon the testimony of Wells, an employee of the plant in claiming the duct burners were operational as of January 1, 2014. However, later in his testimony, Wells admitted that they got the duct burners up and running probably in 2015 (Transcript, page 389). The Board finds Wells' testimony herein was contradictory and may have been tainted by his prior relationship with Rockland Capital. Wells admitted in his testimony that he was upset at Rockland Capital when they initially purchased the subject property because of their description of the surrounding Grand Tower location as a place no one would want to work at.

The Board finds Reilly's use of net capacity was consistent with the subject's actual operation as a peaking plant instead of gross capacity which would have included the non-operational duct burners. Reilly further explained that his discount rate was reflective of the condition of Grand Tower and the amount of risk associated with using a combined cycle plant as a peaking plant in the MISO market. Reilly explained that part of the risk was the extended start-up times with a heat rate of 8,400 wherein gas is being expended without producing power. Beach also testified that Grand Tower was in a market with more risk than the PJM market with its known 3-year rolling capacity market. Further, Rapenske testified that the subject presented financial risk due to its high forced outage rate and low capacity factor of 8%, which he stated was not typical for a combined cycle plant. The Board finds this testimony supports the amount of risk Reilly associated with the subject plant and is reflected in his concluded discount rate utilized in his discounted cash flow analysis.

Lagassa also developed a discounted cash flow analysis but did not develop a direct capitalization method because he opined that where predicted income is volatile or where net revenues are expected to experience variable change in future years, the discounted cash flow is a more reliable analysis because it examines annual net operating incomes and discounts them to present-value, using the required rate of return as the discount rate, and sums the results to determine a net present-value. (Intervenor's Exhibit No. 5, page 58) Lagassa explains in his report that income for a power station comes from payment for electric energy sold, payment for installed and available capacity and payment for ancillary services. Using a five-year average output at the subject plant and heat rate as predictive of future operations, Lagassa concluded a five-year average net capacity factor at Grand Tower was 8.9%. Given expected increases in production at Grand Tower and the continued low cost of natural gas, Lagassa assumed that as of January 1, 2014, Grand Tower was expected to operate at an average annual plant factor of approximately 9.5% going forward with a matching heat rate of 7,500 Btu/kWh. Lagassa explains on page 60 of his report that 2014 ancillary services provide approximately 50% of gross marginal revenues and were forecast to remain steady while capacity revenues were forecast to grow significantly over the next decade, proving a lion's share of revenue at Grand Tower.

In regard to the price for power, Lagassa utilized a base price of $5/MWh for wholesale electric power sales in 2013 and then inflated or deflated the base number dependent on the rate of change in natural gas prices as forecast by the U.S. Energy Information Administration in its Annual Energy Outlook for 2014. Reilly reported that the price of natural gas will set the price for electric power at the margin and is the primary driver of electricity market prices. Reilly then opined that it was reasonable to expect significant increases in capacity prices going forward, and therefore, he used a price of $16.75/MW-day price for capacity and thereafter doubled the capacity price in 2015 and again in 2016 until the total capacity payment reached $90/MW-day in 2017. From this, he then escalated the $90 value with inflation. Lagassa then analyzed the subject's operating expenses. Lagassa adopted the forecast nominal gas prices in the subject's region as set forth in the Annual Energy Outlook 2014 Early release. Lagassa then estimated first year non-fuel operating expenses (employment, operations and maintenance costs) from 2007 at 0.93 cents/kWh, to which he escalated to 2014 to arrive at non-fuel operating expenses of $1.068 cents/kWh. This resulted in first year non-fuel operating expenses at $0.0107/kWh which he inflated by 2% per year thereafter in his discounted cash flow analysis. Lagassa then applied administrative and general expenses of 7.5% as indicated by benchmark companies. Lagassa then examined the previous five-year emission allowances at Grand Tower from the FERC Form 1 filings which indicated an annual emissions allowance expense of approximately $42,800. After allowing for inflation and uncertainty, Lagassa concluded a first-year emissions allowance expense in 2014 of $49,000, which would escalate with inflation thereafter. Based on information provided by Rockland Capital, Lagassa incorporated all of the capital expenditures contained in the 11-year and 6-year forecasts and concluded the subject's 2025 forecast major maintenance budget of $254,000 with inflation. Lagassa then examined the working capital of benchmark companies which indicated working capital requirements from 2012 to 2014 as a negative 1%. For purposes of his discounted cash flow analysis, Lagassa assumed working capital of 4% of the incremental change in total revenues from year to year, with year 1 being zero. Lagassa assumed expense would inflate 2% per year going forward. Lagassa concluded a

base discount rate of 8.59% based on the typical cost of debt, degree of leverage of a typical power plant investment and the required rate of return on equity.

Cost of debt was determined to be 6.1% and the degree of leverage was determined that the average debt/equity ratio was approximately 55% to 45%. From this, Lagassa posited a degree of leverage composed of 40% equity and 60% debt as of January 1, 2014. For the required return on equity, Lagassa estimated 11.2%, to which he adjusted to 11.7% after estimated income taxes. Lagassa then applied a total discount rate of 10.19% to the pre-tax net operating income which Lagassa opined was a fair discount rate for the subject under market conditions existing as of the assessment date. Lagassa's report depicts on page 71 that his discounted cash flow analysis assumes perpetual asset life due to life extension based on regular capital expenditures and sale of the asset at the end of the posited holding period in 2035. In order to measure the value of Grand Tower after the assumed holding period, Lagassa used a residual capitalization rate which was equal to the discount rate of 8.91% less growth of 3.35% or 5.56%. He then applied the going-out capitalization rate plus a property tax factor of 1.284% to the net operating income during the year 2035 and by discounting it using the discount factor the previous year, Lagassa estimated the reversionary value of Grand Tower. Lagassa concluded that the total retrospective value of Grand Tower by the income approach to value as of January 1, 2014 was $231,220,000 and was $198,821,000 as of January 1, 2015 using the same methodology.

The Board finds Lagassa did not sufficiently support his use of a 9.5% capacity factor. The record depicts a 9.5% capacity factor exceeds every year but one in Grand Tower's operating history from 2009 to 2013. The only year that exceed this amount is year 2012, which the experts agreed was an abnormal year. In fact, the subject's capacity factor in 2014 was 1.7%. As Beach testified, the subject was not operational for much of 2014 which contradicts Lagassa's testimony that the subject plant shaped up very well in comparison to newer plants. The Board finds this contradiction may be supported by the fact that Lagassa relied upon a prior inspection of the subject plant in November 2012; over one year prior to the valuation date of January 1, 2014. In addition, Lagassa's use of certain data in his discounted cash flow analysis was disputed by Green. As Green pointed out, Lagassa utilized a base price of $44/MWh of electric power sales in 2013 and then escalated his base price on projected increases. However, Green testified that the actual weighted average price of energy at the MISO node in 2013 was $30.72/MWh, a difference of $14/MWh. Green's testified that this would crush Lagassa's estimated value because these projections regarding the profitability of Grand Tower would be compounded year over year. Further, Lagassa's report and testimony indicates he inflated income from ancillary services and explains on page 60 of his report that 2014 ancillary services provide approximately 50% of gross marginal revenues and were forecast to remain steady while capacity revenues were forecast to grow significantly over the next decade, proving a lion's share of revenue at Grand Tower. However, as counsel points out in contradiction, Federal Energy Regulatory Commission document 14-01238-000 depicts "the actual ancillary service is a fixed payment that does not escalate." The Board finds the record herein depicts this escalation error may lead to an improper estimation of value based on the testimony of Green.

Green testified that the biggest problem in Lagassa's income approach to value in terms of dollars was the inclusion of a reversionary value for a plant that at the end of his projection period will have 35-year old combustion turbines/heat recovery steam generators and 80-year old

steam turbines. Green testified that this added $70 million to Lagassa's estimated 2014 and 2015 values. Green stated this was in direct contradiction to Lagassa's assumed useful lives that he used in the cost approach for those very components and found this incredible. Green stated that if Lagassa assumed the plant would be kept in a state of new condition based on maintenance practices, there was no evidence of the capital expenditures forecast in the report to support it. Green found this to be an incredible assumption as there should be no terminal value in his opinion.

Based on an examination of the income approaches to value used by both appraisers, the Board finds the two methods employed by Reilly, the direct capitalization approach and the discounted cash flow analysis are better supported and more credible than the discounted cash flow analysis developed by Lagassa. Reilly was able to sufficiently defend his methodologies through testimony and was supported by the testimony of other witnesses. The Board finds Reilly's income approach to value incorporates the operational history of the subject plant as a peaking plant in the MISO-Illinois market and better represents the subject's estimated fair market value for a power generation facility operating in its regulated power market. Lagassa, on the other hand utilized installed capacity as a unit of measure and appears to have unduly inflated data in his discounted cash flow analysis of which the subject is not able to attain within the market in which the subject operates. As Beach testified, Grand Tower operates in a market where it can only get paid for what is in that market. The unrefuted record depicts power generators such as the subject are called upon to produce electrical energy into the power grid from Independent System Operators ("ISO") and Regional Transmission Organizations ("RTO"). It is these system operators which govern the power demands throughout various regions of the country. The Board finds this organized distribution of energy throughout the power generation industry limits the operational characteristics of the subject plant as a peaking plant as of January 1, 2014 and January 1, 2015, and therefore limits the utility of the subject plant and its ability to produce revenue. The Board recognizes that with the decrease in natural gas prices and the increase in natural gas supplies, along with the closing of many coal-fired plants , the utility of the subject plant is expected to increase. However, as of the valuation dates in question, the subject's limitations are inherently clear.

Reilly's report depicts his final conclusion of value wherein he found the cost and income approaches indicated a fairly tight range of fair cash value, while the sales comparison approach deviated from the cost and income approaches. Reilly states all approaches were considered in his final conclusion of fair cash value for the subject in order to capture all market influences. Reilly did however recognize that the subject is an income-producing property and that investors and potential purchasers of such property would primarily rely on development of an income approach analysis, and therefore, he gave a majority of weight in his analysis to the income approach in the reconciliation and final conclusion of value. Reilly explained that because of the complexities involved in industrial facilities such as the subject with its unique physical attributes and unknown intangibles, true comparability to a subject facility is highly difficult to determine, and therefore, the sales comparison approach was given minimal weight.

Lagassa states in both of his appraisal reports that the cost methodology is brought into question by the fact that it results from a very large deduction made for economic obsolescence based on uncertain forecast electric power prices. Lagassa goes on to state however that it is supported by

the fact that it is within the range of values suggested by the sales comparison approach. Lagassa also opined that because the cost approach measures the value of tangible assets, the cost approach is appropriately lower than the value indicated by the income approach, which includes both tangible and intangible asset value. Lagassa indicated a strong confidence in his income approach to value because it was also within the range of values indicated by his sales comparison approach. Lagassa admitted that his market approach may have been impressionistic and lacking in precise measurement, nonetheless, he was confident in the established range. Lagassa then gave equal weight to all three approaches to value in concluding his final opinions of value for the subject.

The Board next examined the subject sale in January 2014 in relation to supporting or contradicting the final conclusion of value as found by the appraisers. The record herein depicts Rockland Capital purchased the subject property along with power generating facilities in Elgin and Gibson City from Ameren in a portfolio transaction wherein a purchase agreement was signed in December 2013 and the transaction closing in January 2014. The appellant ultimately paid $168 million plus adjustments for working capital for the three properties. (transcript, page 45)

Appellant's counsel argues the transaction was an arm's length sale, while intervenor argues the transaction was a "fire-sale" because Ameren was getting out of the unregulated market and was selling all of its coal-fired plants. The price allocated to Grand Tower in the transaction was $47 million. The evidence depicts Rockland Capital was required to increase its initial bid for the three properties at least two times prior to paying the final sale price of $168 million. Rockland Capital's initial bid was $143 million, which was then raised by $20 million to $163 million and then raised again to $168 million just days before the purchase agreement was to be signed. (transcript, page 40)

The Board finds neither appraiser gave much weight to the allocated sale price of $47 million to Grand Tower because of the unknowns associated with the sale. Likewise, the Board gives little weight to the allocated sale price of $47 million and therefore, its allocated price is not given much weight in this decision. However, the Board finds the sale transaction, which occurred in close proximity to the valuation dates in question, should be considered in regard to the credibility of the final conclusion of value found in each appraisal report.

The evidence herein depicts the subject was the least valuable asset in the portfolio transaction and was in a state of disrepair at time of purchase; see transcript, pages 69 - 71. Further, Rapenske testified that part of the issues were personnel and part were the procedures they were using. They went through each maintenance task and found what was deferred and what was not. They looked at the electrical equipment, the electrical leads, the duct burners, intake screens, etc. Rapenske stated they could not continue to operate the plant in the condition it was in without receiving the same poor statistics. During the first two years, they had just scratched the surface and began to identify the issues.

The Board finds the subject's sale in 2014 contained the necessary elements of an arm's length transaction as a sale between a willing buyer and a willing seller not under duress. The Board finds the subject's sale was well advertised and utilized methods generally used to transact the

sale of power plants in the open market. The record indicates this resulted in negotiated bidding between multiple parties. Nothing in this record depicts Ameren was under duress to sell the subject; only that its intentions at the time of sale was to remove itself from the coal-fired unregulated power markets. The testimony herein indicated Ameren was trying to maximize the sales price it received in the portfolio transaction.

The Board finds Lagassa's final opinion of value for the subject alone in the amount of $220 million incredulous and illogical when the total sales price for three power generations facilities (Grand Tower, Elgin and Gibson City) totaled $168 million. The Board finds Lagassa's estimated final opinion of value for one property is significantly higher than what the appellant paid to purchase three properties in a portfolio sale. The Board finds the reasoning for this discrepancy was not well established or explained in the testimony or contained within his appraisal report. Therefore, the Board finds this issue greatly discredits the final opinion of value for the subject as estimated by Lagassa.

The Board further finds the board of review presented no evidence in support of the subject's 2014 and 2015 assessment. The assessments for both tax years was based on an appraisal submitted by the intervenor to the Jackson County Board of Review.

The subject's assessment for both the 2014 and 2015 tax years was $31,538,245 for all parcels affected herein. The subject's assessment reflects a market value of approximately $94,994,714 for 2014 and approximately $95,339,314 for 2015.

Reilly concluded a final opinion of value for the subject of $20,000,000 as of January 1, 2014 and testified his opinion of value would not be significantly different as of January 1, 2015.

Lagassa concluded a final opinion of market value of the taxable real property of Grand Tower as of January 1, 2014 of $101,112,000 with the reconciled going concern value being $220,000,000. Lagassa also concluded a final opinion of market value of the taxable real property of Grand Tower as of January 1, 2015 of $91,963,000 with a reconciled going concern value being $200,000,000.

Based on the testimony and evidence presented in this record the Board finds the appellant has shown by a preponderance of the evidence herein that the subject is overvalued as reflected by its assessments for years 2014 and 2015, and therefore reductions are warranted commensurate with the stipulated methodology above.

Based on this record, the Property Tax Appeal Board finds the subject property had a market value of $20,000,000 as of January 1, 2014 and $20,000,000 as of January 1, 2015.

This is a final administrative decision of the Property Tax Appeal Board which is subject to review in the Circuit Court or Appellate Court under the provisions of the Administrative Review Law (735 ILCS 5/3-101 et seq.) and section 16-195 of the Property Tax Code. Pursuant to Section 1910.50(d) of the rules of the Property Tax Appeal Board (86 Ill.Admin.Code §1910.50(d)) the proceeding before the Property Tax Appeal Board is terminated when the decision is rendered. The Property Tax Appeal Board does not require any motion or request for reconsideration.

Chairman

Member

Member

Member

Member

DISSENTING:

C E R T I F I C A T I O N

As Clerk of the Illinois Property Tax Appeal Board and the keeper of the Records thereof, I do hereby certify that the foregoing is a true, full and complete Final Administrative Decision of the Illinois Property Tax Appeal Board issued this date in the above entitled appeal, now of record in this said office.

Date: June 18, 2019

Clerk of the Property Tax Appeal Board

IMPORTANT NOTICE

Section 16-185 of the Property Tax Code provides in part:

"If the Property Tax Appeal Board renders a decision lowering the assessment of a particular parcel after the deadline for filing complaints with the Board of Review or after adjournment of the session of the Board of Review at which assessments for the subsequent year or years of the same general assessment period, as provided in Sections 9-125 through 9-225, are being considered, the taxpayer may, within 30 days after the date of written notice of the Property Tax Appeal Board's decision, appeal the assessment for such subsequent year or years directly to the Property Tax Appeal Board."

In order to comply with the above provision, YOU MUST FILE A PETITION AND EVIDENCE WITH THE PROPERTY TAX APPEAL BOARD WITHIN 30 DAYS OF THE DATE OF THE ENCLOSED DECISION IN ORDER TO APPEAL THE ASSESSMENT OF THE PROPERTY FOR THE SUBSEQUENT YEAR OR YEARS. A separate petition and evidence must be filed for each of the remaining years of the general assessment period.

Based upon the issuance of a lowered assessment by the Property Tax Appeal Board, the refund of paid property taxes is the responsibility of your County Treasurer. Please contact that office with any questions you may have regarding the refund of paid property taxes.

PARTIES OF RECORD

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