City of Brownsville

Brownsville Public Utilities Board

Tenaska Project

Forensic Examination Report
September 29, 2022

CARR RIGGS & INGRAM
CPAs and Advisors
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September 29, 2022

Mr. Victor Flores
Brownsville City Attorney
1001 East Elizabeth Street
Brownsville, TX 78520

Dear Mr. Flores:

Carr, Riggs & Ingram, LLC ("CRI") was engaged to provide forensic services to the City of Brownsville ("COB") for the purpose of investigating the activities of the Brownsville Public Utilities Board ("BPUB") leading up to and occurring subsequent to the formulation of an agreement with Tenaska ("Tenaska"), to build and operate a gas-fired electric generating station (the "Project"), and a related gas pipeline (the "Pipeline").

We have performed this engagement in accordance with the Statement on Standards for Forensic Services as promulgated by the American Institute of CPAs ("AICPA"). While our work involved analysis of accounting records, our engagement did not constitute an audit in accordance with generally accepted auditing standards, an examination of internal controls, or any other attestation or review service in accordance with standards established by the AICPA. Had other procedures been performed, other matters may have come to our attention that may have affected the findings reported herein.

1. Objectives

The objectives of our forensic engagement were to:

1. Ascertain whether there were any improper activities conducted in furtherance of the Project.
2. Provide an accounting of all funds set aside for and expended in connection with the Project.
3. Evaluate the propriety, nature, and timing of expenditures made in furtherance of the Project and the accumulation of costs consisting of recorded construction-in-progress asset(s).
4. Determine the amount and disposition of any funds raised or collected in furtherance of the Project.
5. Document the justification of the Project and evaluate its reasonableness.
6. Ascertain that all activities and transactions were initiated under either specific or general approval.
7. Provide Brownsville, through its City Attorney, a final report identifying whether any irregularities or illegal acts were detected in connection with all transactions identified in the scope of services. The report shall detail any evidence, if any, of illegal or irregular acts.

2. Scope

The scope of our investigation was limited to what we could determine was the origination of the discussions leading up to the Project in FY 2011 and concluding with the date of our report.

3. Background

Since the COB Commission (the "Commission") amended the charter in 1960, BPUB has been the major provider of electric, water, and wastewater services to customers in the Brownsville area. The utility has the largest load of three electric providers in the city and currently owns, in part or wholly, two power plants and distributes power through 4,000 miles of wires and 14 substations. It is the only city-owned electric provider in the Rio Grande Valley.

The Electric System provides retail electric service through its electric facilities to consumers inside and outside of the Brownsville city limits. The existing customer service area of the electric facilities encompasses approximately 133 square miles of Cameron County, including substantially the entire city of Brownsville. The electric system serves a base of some 50,000 customers and has a peak load of 305 megawatts ("MW").

Under the terms of the City Charter, BPUB is comprised of seven members (the "Board" collectively), six of whom are appointed by the Commission for four-year terms. The seventh member is Brownsville's Mayor serving ex-officio. The Commission fills Board vacancies as they arise but, absent a vacancy, may only remove one Board member in any 12-month period upon unanimous vote of the entire Commission.

Article VI of the City Charter gives BPUB absolute and complete authority and power over the control, management, and operation of the power and light, water, and sewerage systems owned by the City. However, BPUB does not have the right to encumber, sell, or pledge the assets of the utilities system, nor can it unilaterally set utility rates or approve the issuance of debt. The setting of rates and approval of debt fall under the purview of the Commission.

BPUB appoints a general manager and chief executive officer that is responsible for retaining and managing a staff to operate the System.

Throughout the timeframe of the Project, the BPUB management team ("Management") has been:

- John Bruciak, GM/CEO
- Fernando Saenz, Assistant GM/COO[1]
- Leandro Garcia, CFO[2]
- Marilyn Gilbert, former Director of Energy Services and Energy Risk Manager[3]

Prior to October 1, 2020, BPUB met its power supply obligations through a combination of resources. These included the Oklaunion plant[4], the Silas Ray Power Production Facilities, and the Calpine/Hidalgo combined-cycle Power Plant.

BPUB issues its own set of audited financial reports but as a component unit, is also included in the COB's Comprehensive Annual Financial Report ("CAFR"). The financial statements of BPUB include a blended component, Southmost Regional Water Authority, which provides treated water to various parts of Cameron County. BPUB holds a 92.91% ownership interest in the water authority. BPUB is a single

[1] Fernando Saenz retired from BPUB in mid-2022.
[2] Leandro Garcia resigned from BPUB in late 2020.
[3] Ms. Gilbert left BPUB in 2014 and returned in 2022, serving in the capacity of Assistant GM/COO.
[4] The Oklaunion plant was sold to an unrelated party in 2020.

enterprise fund that is organized on the basis of the three systems of electric, water, and wastewater, each of which is considered a separate accounting entity.

In the summer of 2011, BPUB was in the process of developing an Integrated Resource Plan ("IRP") which would aid BPUB in long-term planning by evaluating supply and demand for energy services. Black and Veatch ("B&V") was awarded the Professional Engineering and Technical Services contract to study and write the IRP.

In the late summer of 2011, Management contacted Tenaska to express interest in locally building a generating station to meet anticipated capacity shortfalls predicted by the IRP. Tenaska responded that it was interested in locating a facility in Brownsville. In October 2011, a non-disclosure agreement was executed between BPUB and Tenaska to facilitate discussions. In December 2011, Tenaska was invited to make a presentation at a BPUB closed executive session.[5]

Nearly one year after the Tenaska presentation before the Board, BPUB signed a Memorandum of Understanding ("MOU").[6] BPUB negotiated the MOU and subsequent agreements with the aid of contracted consultants. The finalized agreements[7] (the "Definitive Agreements") were executed January 25, 2013 with the commercial operational date ("COD") of the Tenaska Brownsville Generating Station ("TBGS") scheduled for June 2016.

In order to meet its Project financing obligations and operations and maintenance ("O&M") costs, BPUB made a rate presentation to the COB Commission. A component of this presentation was an Electric, Water, and Wastewater Evaluation and Recommendation that B&V prepared. The Commission approved a series of five rate hikes, with the first taking effect April 1, 2013 and the last on October 1, 2016. This series of rate hikes increased the electrical rates by a total of 36%[8] over four years, or 41.57% when compared to pre-Project rates. In addition to the rate increase ordinance, the COB approved an ordinance establishing a gas utility under the control and management of BPUB. The rate ordinance required BPUB to file a Cost of Service Study to allocate the rate adjustments by customer. B&V completed the Cost of Service Study in February 2013.

The Project was to be an 800 MW natural gas-fired power plant. The COB would be entitled to 200 MW of power, and Tenaska would be required to sell or find subscribers for the remainder of the capacity. BPUB negotiated an agreement to provide the natural gas transportation to the plant via a BPUB owned pipeline (the "Pipeline") spanning approximately 50 miles, thus requiring the acquisition of land Right of Ways ("ROW"). Construction of the Project would not commence until Tenaska found subscribers for the remaining capacity. BPUB and Tenaska agreed at least six times to extend the agreement deadlines to give Tenaska more time to find subscribers. Eventually the lack of subscribers led to the final termination of

[5] Under Texas Code Title 5, Subtitle A, Chapter 551, Subchapter D, Section 551.086, sensitive competitive matters may be discussed in closed session.
[6] Memorandum of Understanding Signed November 1, 2012.
[7] The eleven agreements which made up the Definitive Agreements are: the Asset Purchase Agreement, Joint Ownership and Operations Agreement (Operations Period), Temporary Joint Ownership and Operation Agreement (Construction Period), Asset Management Agreement (Operations and Maintenance Agreement), Energy Management Agreement, Gas Transportation Agreement, Construction of Gas Transportation Facilities, Water Supply Agreement, Energy Manufacturing Agreement (In-Lieu Tolling Agreement), Netting Agreement, and the Fuel Supply and Management Services Agreement.
[8] Approximately one-half of the rate increase intended for O&M.

the Project. Formal notice of the Project's termination was not provided to the COB until August 2020. Of the approximately $118 million in revenue attributable to Project-related rate increases, approximately $35 million had been spent on the Project, while $29 Million was set aside in a Tenaska Equity Fund, and $54 Million[9] was allegedly allocated to fund rate reductions beginning in April 2016.

On November 1, 2021, CRI was engaged by the COB to conduct a forensic analysis of the events leading up to and subsequent to the formation of the Project.

4. Source Documents

A listing of the documents that we examined in connection with our forensic investigation is attached to this report as Appendix A.

5. Summary of Procedures Performed

1. In order to gather information regarding the activities and inner workings of BPUB and to gain an understanding of the practices, policies, and procedures during the period under investigation, we conducted interviews with the following Brownsville and BPUB personnel and their outside consultants:
    a. Melida Pinales, BPUB Internal Audit
    b. Victor Flores, COB City Attorney
    c. John Bruciak, BPUB GM/CEO
    d. Fernando Saenz, BPUB Assistant GM/COO
    e. Leandro Garcia, Former BPUB CFO[10]
    f. Noe Hinojosa, Financial Advisor
    g. Nurith Galonsky, COB Commissioner and former BPUB Board chair
    h. Jessica Tetreau, COB Commissioner
    i. John Cowan, COB Commissioner
    j. Rose Gowan, COB Commissioner
    k. Tony Martinez, former COB Mayor
    l. James McCoy
    m. Daniela Gonzalez
    n. Carlos Garza
    o. Zeus Yanez
    p. Miguel Perez, BPUB CFO
    q. Eddy Hernandez, BPUB IT Director
    r. Other BPUB operations staff
2. We reviewed email correspondence among BPUB, Tenaska, and outside consultants from 2011-2021.
3. We obtained and reviewed various studies, forecasts, IRPs, and their corresponding presentations from 2011-2020.
4. We analyzed historical electric generation and peak load.
5. We obtained, reviewed, and analyzed invoices and/or related records pertaining to the consultants, engineers, lawyers, and advisors associated with the Project.

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[9] As of August 2020.
[10] CRI attempted to contact Mr. Garcia several times but was not able to speak to him personally.

6. We reviewed BPUB closed session meeting minutes from 2011 – 2020.
7. We reviewed BPUBs budgets and Comprehensive Annual Financial Reports from 2011 – 2020.
8. We obtained, reviewed, and analyzed records of BPUB billings and Fuel Purchase charges for FY 2011-2021.
9. We reviewed the letters of intent, memorandum of understanding, Definitive Agreements, and extensions associated with the Project.

6. Findings

The following summarizes the findings of our investigative procedures described above. The appendices attached to this report provide additional information related to our findings.

6.1. ORIGINS OF THE PROJECT

6.1.1. Background

In the subsections below, the major events and/or relevant documents leading to the execution of the Definitive Agreements in January 2013 are identified and discussed.

6.1.1.1. 2009 Load Forecast

Load forecasts provide information on projected energy demand for a utility system. A load forecast is a critical input to many utility planning activities including power supply planning, transmission and distribution facilities planning, and fuel and purchased power budgeting. Short-term daily, weekly, or monthly forecasts are used at the operations level to help determine the need to purchase additional capacity, decrease generation, or sell surplus capacity, whereas long-term load forecasts are used to project annual demand 20 years into the future. According to BPUB documents, their plan has been to update their long-term load forecast every two years. R. W. Beck, Inc. ("Beck") was retained by BPUB in 2008 to prepare a long-term forecast of retail electricity sales, energy requirements, and peak demand of the BPUB electric system (the "Beck Forecast").

The Beck Forecast was prepared for the 20-year period beginning calendar year 2009 through 2028 and relied on an econometric approach[11] to forecast retroactive retail electricity sales over the period 1994 through 2008 based upon certain explanatory factors that were found to be highly correlated to retail sales. A forecast of system energy requirements, or net energy for load ("NEL"), was then derived from both the retail sales forecast and an estimate of distribution system losses. Finally, a forecast of the system peak demand was calculated from the forecasted NEL and load factors based upon a regression analysis of historical load factor.

According to Beck, the econometric forecast of electric sales relies on system data provided by BPUB and a variety of other data provided by third parties. BPUB staff provided historical data regarding retail customer counts, sales, and revenues; net energy for load; and peak demand, as well as certain anecdotal information regarding its customers and expected customer growth. Beck obtained historical and projected

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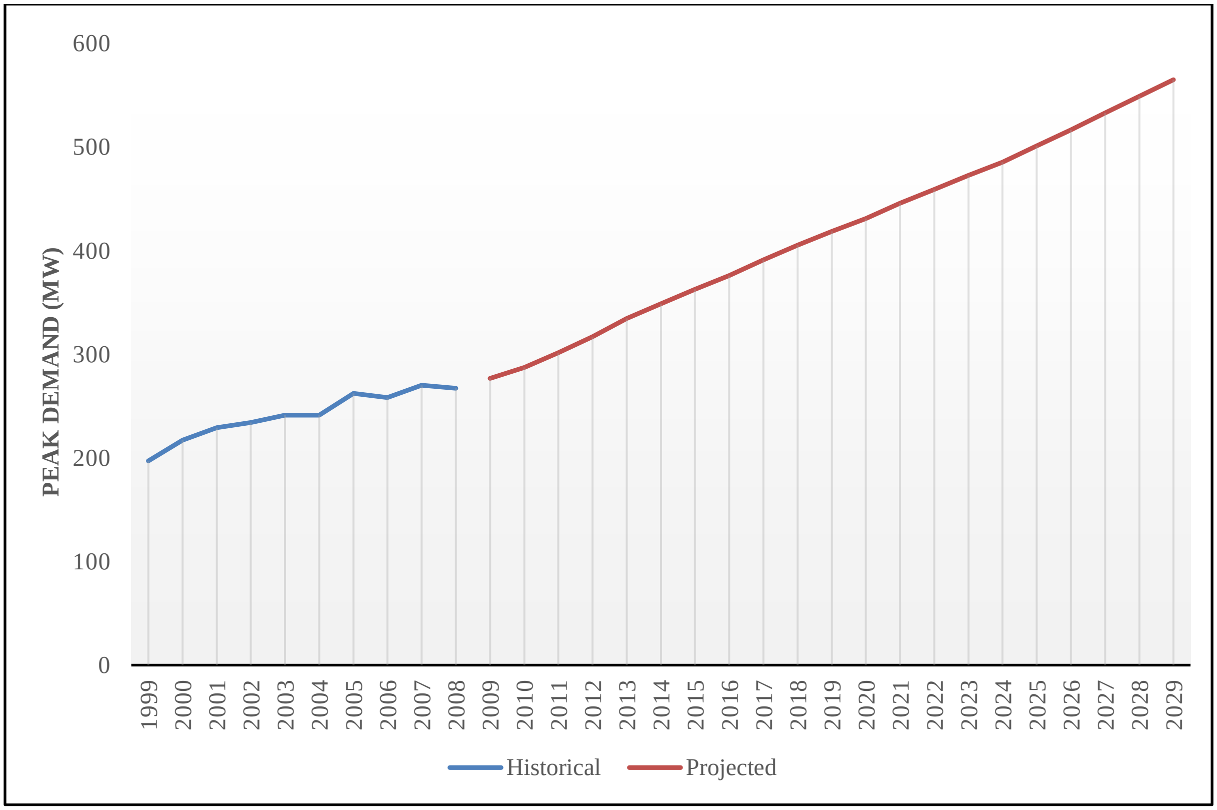
[11] Econometric forecasting makes use of regression analysis to establish historical relationships between a variable of interest, such as energy consumption, and various explanatory variables based on economic theory and experience. In this approach, the significance and validity of historical relationships are evaluated using various statistical measures and theoretical tests. Regression equations that best explain the historical variation of energy consumption are selected.

economic and demographic data for Cameron County, which surrounds BPUB's service area, from Moody's Economy.com and Woods & Poole Economics, Inc.

The Beck Forecast concluded that system energy requirements were expected to grow at annual average rates of 4.2% from 2009-2018 and 3.0% from 2019-2028. System annual peak demand (in MW) was expected to grow slightly faster, at 4.3% per year from 2009-2018 and 3.1% over 2019-2028. The results of the Beck Forecast reflected annual peak demand growing to 405.0 MW by 2018 and to 548.7 MW by 2028, as reflected in Figure 1below.

Figure 1



However, the Beck Forecast described a number of uncertainties and potential errors in the assumptions and historical and projected data, which were the principal drivers of its model, including the following:

> *"The data on which this forecast is based, both external (economic, weather, etc.) and internal (energy sales, peak demands, etc.) are assumed to be accurate. While R. W. Beck has reviewed the data for major anomalies, we can give no assurances that the data are without error. In particular, recent historical economic data (for the period after 2007) actually represent projections by Moody's, as actual data is unavailable. Further, even "actual" economic and demographic data for the most recent several years is subject to substantial revision as more supporting data becomes available. Therefore, the relationships upon which the forecast is based may be in error, as the "true" data could show a different quantitative relationship."*

…

"The future influence on energy sales of the economic, demographic, and weather factors, on which the econometric models are based, was assumed to be similar to the estimated influence of such factors generally over the period 1994 through 2008."

Thus, the 2009 Beck Forecast is based in large part on data from 2007 and prior. Data used to illustrate 2008 was projected by Moody's and likely does not reflect the economic downturn of the 2008-2009 period.

Moreover, the Beck Forecast devoted an entire section[12] to communicating the uncertain and volatile nature of the data underlying the assumptions and the steps Management should take to address these risks.

*"Importantly, as discussed in Section 3, a significant portion of the historical period upon which the forecast is based is not known with certainty but is in fact only estimated…Accordingly, a forecast must be viewed as a guide only, **and plans for large capital expenditures, which are based on such forecasts, made with care and with an allowance for flexibility** [emphasis added]."*

"This forecast should be updated periodically, particularly when events occur that are expected to impact growth or when projections of driving variables change significantly. In addition, it may become useful to create projections that directly estimate the range of uncertainty that can be expected in future electric demand on the BPUB system. Several techniques are available to address the sources of potential error in the forecast...However, the forecasting equations and the infrastructure developed for this forecast are capable of addressing a range of potential risk analysis methods."

To facilitate future adjustment, Beck, at BPUB's request, provided BPUB with monthly forecasts of each key determinant and result, thus providing BPUB an easy means to identify and address the sources of potential error in the forecast or, at the very least, compare the monthly forecasted values to actual as time went on.

6.1.1.2. 2011 Integrated Resource Plan

According to BPUB documents, long-range planning is typically done on a five-year schedule, and amended as needed. The planning cycle typically consists of a load forecast, which projects future power needs, and an IRP.[13]

The IRP is a comprehensive study that aids BPUB in its strategic planning efforts. Because the energy landscape has become more diverse, utility providers need to make determinations about cost, reliability, and sustainability when making decisions about the energy mix of the system as a whole. Typically, an independent engineering firm conducts the study using industry standard models along with inputs from BPUB on its current and historical programs and resources, as well as any planned projects. According to Marilyn Gilbert, a winter storm in February 2011 that exceeded previous peak capacity forecasts necessitated a 2011 IRP update.

[12] Beck Report, Section 5 - Forecast Uncertainty.
[13] BPUB Joint COB August 10, 2020 Power Point Presentation.

According to BPUB documents, a Request for Proposal ("RFP") [14] was circulated to three engineering firms in early 2011. We understand that at least two of the three engineering firms showed interest in submitting a proposal - SAIC (formerly R.W. Beck) and B&V.[15] B&V was awarded the contract in April 2011.

In addition to developing an action plan, the B&V contracted scope of services stated that the IRP "would address incorporation of gas supply limitations, transmission constraints, additional capacity at Silas Ray, recommended renewable generation targets, percent reserves desired in Cameron County, Demand-side Management and Energy Efficiency, and possible support related to analyzing the Mexican Market."

BPUB was asked to provide a complete and accurate picture of its current and future needs and resources to aid B&V in ensuring that its models had reliable data. To facilitate the IRP modeling, BPUB provided to B&V the Beck Forecast, information on its planned power generation resources, existing conventional and renewable generation resources, energy management programs, fuel supply contracts, etc.

B&V analyzed the data provided and ran a series of models that evaluated expansion plan scenarios to determine the most economic power generation expansion options and the corresponding production cost modeling. After modeling was complete, B&V provided a comprehensive draft of the IRP to Management on December 15, 2011 and an IRP power point presentation for the Board on December 16, 2011.

In mid-December, after the first draft was completed, BPUB requested that B&V consider four additional alternatives: Inlet Fogging, Tenaska and Transmission Alternatives, and Modified Tenaska Alternative.[16]

1. Inlet Fogging - the addition of inlet fogging on Silas Ray Unit 6/9, which BPUB indicated is estimated to provide 7 MW of incremental summer capacity at a capital cost of $1.9 million. Results are reflected in the Modified Reference Case.
2. Tenaska Alternative - participation in a unit proposed by Tenaska through a build-own-transfer arrangement in a new 2x1 7FA combined cycle unit to be constructed within BPUB's service territory. Costs and performance for this alternative were provided by Tenaska.
3. Transmission Alternative - construction of a new transmission line that, based on information provided by BPUB, will allow for 100 MW of additional import capability into the BPUB system at a cost of $18.5 million.
4. Modified Tenaska Alternative - the expansion plan developed in the Tenaska Alternative above was held constant through 2016, and capacity requirements beyond 2016 were met through the addition of 50 MW of incremental capacity from Tenaska. The new wind generation selected in the previous Tenaska evaluation was carried forward to the Modified Tenaska Alternative evaluation.

Rankings of the alternatives against the Modified Reference Case[17] were based on cumulative plant worth costs ("CPWC"). CPWC measures the present value of a summation of the annual costs of a generation

[14] BPUB, citing document retention policies, was unable to provide a copy of the RFP.
[15] Due to document retention policies, BPUB was unable to provide documents pertaining to the rating of the firms that were shortlisted and submitted proposals for the 2011 IRP.
[16] Professional Services Contract Amendment dated December 21, 2011.
[17] A case developed to evaluate the economics of an expansion plan in which BPUB's projected capacity requirements were satisfied in the 2012 through 2015 timeframe through market purchases, adding Inlet Fogging in 2016.

plan. From three of the four alternatives, BPUB selected the Tenaska Alternative. While the Transmission Alternative was in fact less costly and offered more flexibility, BPUB elected not to pursue this alternative.

Table 1

YEAR	MODIFIED REFERENCE CASE	TENASKA ALTERNATIVE	MODIFIED TENASKA ALTERNATIVE	TRANSMISSION ALTERNATIVE
CPWC ($1000s)	2,594,868	$2,531,111	$2,394,369	$2,525,341

The results of the final 2011 IRP draft,[18] completed on February 16, 2012, and touted by Management as the catalyst for the Tenaska Project, were presented in IRP Section 1.4 *Study Findings* and separated into the following sections: High Level Summary Findings, Conclusions, Recommendations, and Suggested Action Plan. Relevant key points are recapped below.

<u>High Level Summary Findings</u>

- New generation must be located to meet increasing loads or retiring resource, unless additional transmission is built into the Brownsville area.
- BPUB's need for new power was small compared to the output of most new economical power plants. Thus, if transmission is not sufficient to bring in power supplies from outside the Brownsville area and generation is needed, the technology of choice seems to be the Wartsila unit with net capacity of approximately 9.2 MW. These units provide capacity increments that are aligned with the Brownsville need for new power supply. However, smaller units like these are typically more expensive to build and operate than larger units on a per-kW and per-kWh basis.
- Alternative, more economical sources of power may be identified through a competitive solicitation or RFP but sufficient transmission capacity to bring in power from outside Brownsville area would be the first choice.
- BPUB should conduct a competitive RFP for power supply including details on the means of getting power into Brownsville.
- BPUB could bring in 33 MW of power from wind by 2014 without raising rates more than 2%.

<u>Conclusions</u>

- Henry Hub[19] gas prices, a major cost driver for gas-fired generation stations, were projected by B&V to increase year after year and double by 2035.
- Using the Beck Forecast, B&V reported 2012, 2013, and 2014 to be 21, 41, and 57, respectively, below target reserve Peak MW capacity. By the end of the IRP's planning horizon, B&V reiterated

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[18] The final draft reflected revisions and additions based on BPUB requests to add four other alternatives for evaluation: Inlet Fogging of Silas Ray Unit 6/9, the Tenaska Alternative, and the Transmission Alternative.
[19] The Henry Hub pipeline is the official delivery point for futures contracts on the New York Mercantile Exchange. Settlement prices at Henry Hub are used as benchmarks for the North American natural gas market.

that BPUB's need for additional capacity to maintain target reserve margin requirements was approximately 339 MW.

Figure 2

YEAR	FORECAST PEAK DEMAND (MW)	TOTAL PEAK PLUS RESERVE (MW)	EXCESS/ (DEFICIT) CAPACITY TO MAINTAIN REQUIRED RESERVE MARGIN LEVEL (MW)
2012	316.8	360.4	(20.9)
2013	334.3	380.3	(40.8)
2014	348.5	396.4	(56.9)
2015	362.5	412.3	(72.8)
2016	375.8	427.5	(88.0)
2017	391.0	444.8	(105.3)
2018	405.0	460.7	(121.2)
2019	418.5	476.0	(136.5)
2020	430.8	490.0	(150.5)
2021	445.5	506.8	(167.3)
2022	459.0	522.1	(182.6)
2023	472.6	537.6	(198.1)
2024	485.2	551.9	(212.4)
2025	500.8	569.7	(230.2)
2026	516.3	587.3	(247.8)
2027	532.7	605.9	(266.4)
2028	548.7	624.1	(284.6)
2029	564.7	642.3	(302.8)
2030	580.7	660.5	(321.0)
2031	596.7	678.7	(339.2)

- Inlet fogging for Silas Ray #9, recommissioning Silas Ray Unit 5, and the addition of wind energy were all economic decisions (i.e. results were advantageous). The total projected increase in capacity for these steps was estimated to be 38 MW.
- Economies of scale associated with obtaining capacity from larger, more economical units may exist as demonstrated by the Tenaska Alternative.
- Purchasing power from the market to meet system requirements, demonstrated by the Transmission Alternative, may be more economical than adding generating units sized in proportion to the BPUB system.

Recommendations:

- BPUB should continue to monitor ERCOT[20] studies related to transmission capabilities into and out of the Brownsville area, as the ability to import generation from new resources located outside of the Brownsville area is currently limited to approximately 80 MW. If the Public Utility Commission of Texas ("PUCT")[21] does not approve the new Cross Valley transmission line, or if ERCOT chooses not to build additional new transmission for speculative loads,[22] BPUB may want to consider building and owning such transmission itself.
- As demand for natural gas increases over the next 20 years, the projected price of natural gas at Henry Hub is projected to double in real terms. Thus, BPUB should consider the impact of increasing natural gas prices on its generation expansion planning.
- Since B&V forecasted the Eagle Ford Shale contribution to South Texas gas supply will triple between 2012 and 2035 and determined that natural gas supply was abundant and would be even more so in future, BPUB should analyze the availability and cost of contractually or operationally firm pipeline capacity sufficient to provide for the proposed available generation capacity.
- Acknowledging the "vintage" of the Beck Forecast and lackluster state of economy, B&V suggested "consideration should be given to evaluating resource planning decisions in light of sensitivities to these projected growth rates," i.e., a reassessment of the growth rates should be undertaken before basing future resource decisions on them.
- BPUB should consider the likelihood of the Project being constructed as proposed due to capacity commitments not materializing.
- Through an RFP process, BPUB should pursue the opportunity to participate as a joint owner in a unit such as Tenaska, and the opportunity to enter into contracts for firm capacity and energy in the form of a power purchase agreement ("PPA"), subsequent to completion of the IRP. The Power Supply RFP should also allow for proposals involving renewable generating resources. Offers received through the RFP should be evaluated based on not only economics, but also reliability and contributions to fuel diversity as well.

6.1.1.3. 2011 Presentations

Tenaska Presentation

On December 12, 2011, Management brought Tenaska in to pitch the TBGS idea to the Board. In its presentation Tenaska stressed, "Without the new Valley Import Lines and Cross Valley Loop Projects, new loads in BPUB's service territory cannot be served reliably unless generation is added. For this reason it may be difficult to attract new large load customers." Later in the presentation, Tenaska added that the

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[20] The Electric Reliability Council of Texas ("ERCOT"), as the independent system operator for the region, manages the reliable and safe transmission of electricity to 90 percent of the state's electric load. ERCOT schedules power on an electric grid that connects more than 52,700+ miles of transmission lines and 1,030+ generation units. ERCOT is a membership-based 501(c)(4) nonprofit corporation, governed by a Board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature.

[21] The Public Utility Commission of Texas regulates the state's electric, telecommunication, and water and sewer utilities, implements respective legislation, and offers customer assistance in resolving consumer complaints.

[22] ERCOT has authority over electrical transmission that is contained within its territory.

Cross Valley Import Lines and Cross Valley Loop Projects would be required before the Project could move forward so that Tenaska could export excess energy.

Thus, it was presented that the TBGS was needed since there was not adequate transmission into the Brownsville area but adequate transmission would be needed before the Project could move forward. This circular logic seemed to escape the Board's attention, as the focus was geared to the benefits of the Project.

The final slide in the presentation contained next steps for validation and the components of a letter of intent. Tenaska assured the Board that the letter of intent "would have mutually agreeable off ramps or change provisions should these activities not achieve expected outcome within certain time periods."[23]

Management Presentation

In the Special Board Meeting Presentation on Dec 22, 2011 (the "12/22 Presentation"), Management discussed key issues identified in the IRP, recapped the Tenaska Presentation, and provided an update on the IRP's status and its recommendations. Notably, Management stated that the IRP identified a capacity shortage to meet load plus required reserve beginning with 21 MW in 2012 and increasing to 105 MW in 2017. Subsequent charts and tables reflected B&V's projected capacity shortage in the IRP, illustrated in Figure 2 above. In addition to emphasizing imminent capacity shortages, Management also presented transmission constraints and RFP timeline as other key issues identified in the IRP.

Management's recap of the Tenaska Presentation highlighted the potential benefits and a September 2016 operational period. Next steps were identified as:

- BPUB
    - Obtain transmission line approvals by PUCT
    - Finalize IRP
    - Release RFP for power supply
    - Engage Engineer of Record to opine on addition
- Tenaska
    - Work to subscribe remainder of the plant's capacity to relieve market exposure
- Both
    - If Tenaska is selected, work through Memorandum of Understanding and Letter of Intent

Management's update of the IRP status included a discussion of the additional scope items for B&V to evaluate (noted in Footnote 16 above) and current recommendations, including:

- Wait on transmission line approval before issuing RFP
    - RFP may place 345KV solution at risk if issued prior to obtaining PUCT approval
    - Establishes timeline for the transmission in-service date
    - Helps competitive position for BPUB during RFP phase
- Continue to develop a Request for Proposals for public release after PUCT approval is finalized
- Extend the MOU agreement with Sharyland Utility

[23] Tenaska Presentation to BPUB dated December 12, 2011, slide 15.

6.1.1.4. 2012 Studies, RFPs, Presentations, and Events

As illustrated in Table 2 below, several studies were generated and a number of presentations given at BPUB meetings between the signing of the Tenaska letters of intent in 2011 and the execution of the Definitive Agreements on January 25, 2013. The implications of these events, if any, are discussed in the Findings sections below.

Table 2

Date	Event	Description
12/12/2011	Tenaska Presentation	Initial Tenaska presentation to BPUB
12/22/2011	Special Board Meeting	Presentation at BPUB special meeting outlining Capacity Shortage, Tenaska timeline, IRP, and next steps for Board
2/27/2012	2011 IRP	Black and Veatch 2011 IRP presented to BPUB in a closed meeting. Study suggested a capacity shortage beginning in 2013
5/22/2012	Joint COB/BPUB Meeting	Joint meeting held to discuss future power supply requirements relating to Brownsville's growth.
6/26/2012	Special Board Meeting	Black and Veatch presentation on the South Texas natural gas market, Impressions of the IRP, the results of the Technical Assessment, and issues with NG Marketing.
7/27/2012	Non-Binding Term Sheet	Non-binding term sheet with Tenaska signed by John Bruciak restricting BPUB from soliciting other offers or engaging in other substantive negotiations
8/19/2012	Special Board Meeting	B&V and Yzaguirre Group interviewed for consulting roles in the proposed power plant project.
9/12/2012	Go/No-Go Presentation	Black and Veatch and Max Yzaguirre presentation to BPUB detailing impacts of Tenaska project and capability of Tenaska as a partner
9/12/2012	Board Vote	Board vote to develop a Memorandum of Understanding with Tenaska
10/10/2012	Closed Meeting	Memorandum of Understanding was approved by the Board.
11/20/2012	Special Board Meeting	Board updated on Tenaska by Max Yzaguirre.
12/6/2012	Black and Veatch Presentation	Black and Veatch Presentation to BPUB on meeting future utility growth.
12/11/2012	Joint COB Meeting to discuss rate increases.	Rate increases to support maintenance and proposed expansion of systems presented to COB by BPUB
12/17/2012	COB Meeting	Vote on Rate Increases
1/25/2013	Special Board Meeting	1/25/2013 - BPUB board approves the Definitive Agreements

Summary of relevant events leading to Definitive Agreements

6.1.2. Findings

6.1.2.1. 2009 Load Forecast Issues

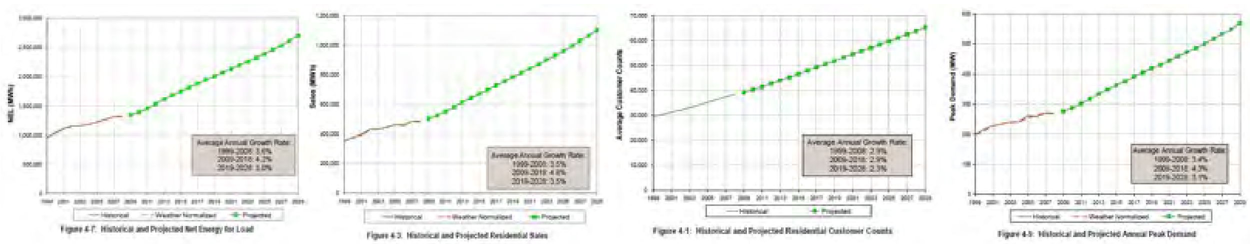
In our review of the results of the 2009 Beck Forecast, we noted the following issues with the variables upon which the forecast is dependent:

- Beck's projection of the Residential Average Use growth rate was well above historical growth rates and was projected to steadily increase.
- Residential customer counts were projected to continue growth of 2.9% per year for 20+ years, an unrealistic assumption.
- Beck projected near-term residential sales growth at a rate well above historical growth at 4.6% through 2019 and 3.5% through 2028.
- The General Service Non-Demand Sales and General Service Demand Sales were both projected to grow above historical rates for the near-term (through 2019).

- Total Retail Electricity Sales and corresponding NEL both projected to grow 4.2% for near-term, which is again higher than historical and counter to the recent leveling off trend.
- Peak Demand also projected to grow 4.4% in near term, which is again higher than historical and counter to the recent leveling off trend.
- The forecast utilized an anomaly[24] in 2000, which may have artificially inflated the average growth rate.

When viewed together, the forecast graphs look very similar; all project the same consistently rosy, above average growth, as illustrated in Figure 3 below.

Figure 3



Throughout the Beck Forecast, the uncertainty of key variables and the potential for deviation are noted, as illustrated in Section 7.1.1.1 above. In fact, the concluding section of the 2009 Load Forecast reiterates that the drivers of the forecast (population, economic forces, and weather) are anything but predictable and can deviate wildly in the short and/or long term. Beck further notes that plans for large capital expenditures based on this forecast, such as the TBGS, should be "made with care and with an allowance for flexibility." More importantly, Beck notes that the forecast should be updated periodically, especially when projections of driving variables change, such as population and economic growth, as they undoubtedly did following the 2008 economic recession and the climbing unemployment rate in Brownsville.

Moreover, as noted in 6.1.1.1 above, Beck provided BPUB with the means to identify and address the sources of potential error in the forecast or, at the very least, compare the monthly forecasted values to actual as time went on. Doing so would have highlighted the need to update the forecast long before BPUB made the decision to proceed with the Tenaska Project. Yet, BPUB did not do so.

6.1.2.2. <u>2011 IRP Issues and Flaws</u>

<u>Flaws in Variables, Assumptions, and Methodology</u>

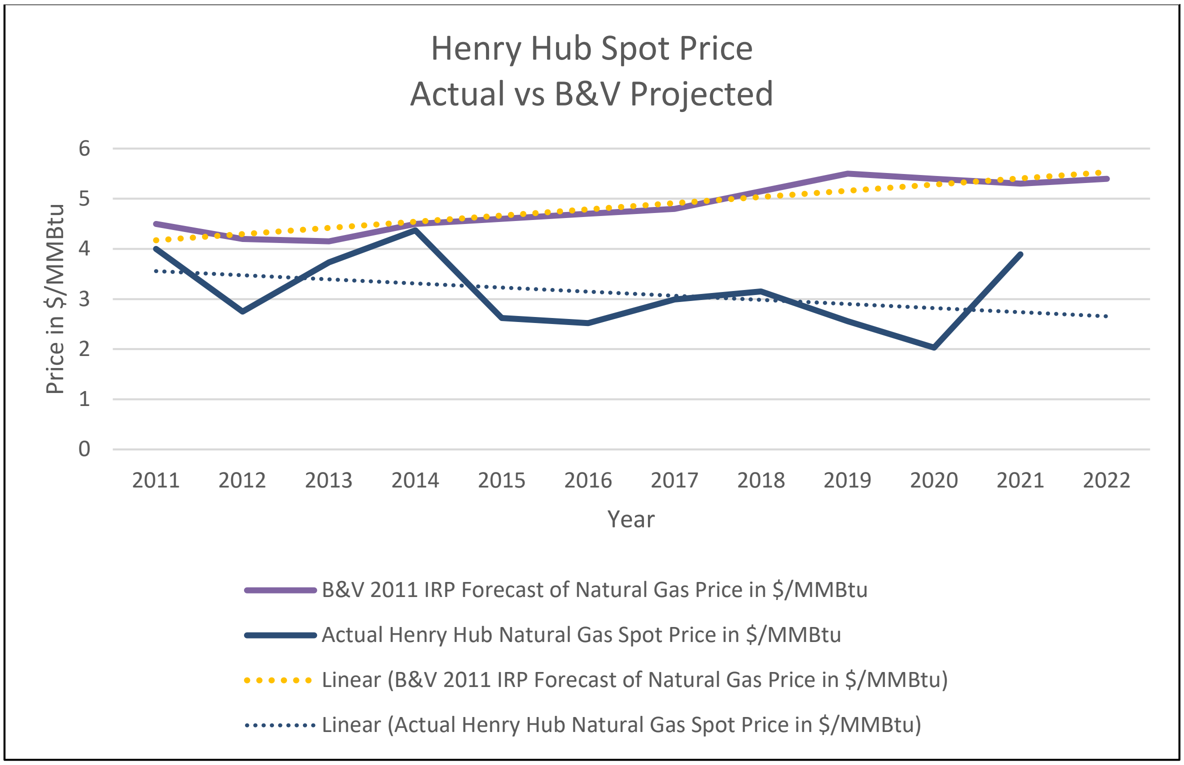
In our review of the results of the 2011 IRP, we noted the following issues with the variables, assumptions, and methodologies employed in the report:

- B&V concluded that Henry Hub gas prices are projected to increase year after year[25] and double by 2035 – a conclusion that was repeatedly proven wrong year after year.

[24] Peak Demand was up 10.2% and NEL up 8.7%.
[25] 2011 IRP Section 1.4.2.

- At the same time, B&V forecasted Eagle Ford Shale contribution to South Texas fuel supply would triple between 2012 and 2035, concluding that natural gas supply was abundant and would be even more so in future – contradicting their assumption that gas prices will double in the same period and contrary to the law of supply and demand.

Figure 4



- B&V's model assumes all costs of fuel go up about the same rate, an unlikely occurrence. B&V also assumes CO2 emissions allowance costs of $27/ton starting in 2020 and increasing to $67 by 2031, which was speculative given that it was based on potential legislation nine years in the future.

- B&V's model is based upon on-peak and off-peak energy prices for spot market purchases that reflect prices ranging from $34 in 2012 to $134 in 2031, a substantial increase supported only by B&V's proprietary model. In contrast, the 2017 IRP is based on prices ranging from $22.7 in 2017 to $84.6 in 2032, presumably based on the same modeling program.

- B&V's peak summer demand forecast and projected capacity shortage is based completely on the 2009 Beck Forecast, which was modeled using actual data from 2007 and prior years and had other flaws as described in Section 6.1.2.1 above.

- B&V included a "required"[26] reserve margin of 13.75% on top of a MW forecast that was already overstated.

- B&V's modeling assumed that only 50 of 80 MW of transmission capacity can be used for spot purchases and assumed that "any new firm supplies that BPUB will need to acquire to meet its

[26] The "required" capacity reserve is addressed in section 6.1.2.3.1 of this report.

planning reserve targets or renewable targets, will need to be located in the greater Brownsville area."[27] However, these assumptions were flawed given that B&V acknowledged in the IRP that ERCOT's Board unanimously endorsed the Cross Valley Line Project[28] in early January 2012, rendering these assumptions moot.

B&V went on to note that the Transmission alternative was more favorable than the Modified Reference Case or the Tenaska Alternative, provided that transmission capability was part of the offers for power. Given the unanimous endorsement of the Cross Valley Transmission Project, transmission capability was assured. Yet, this more favorable alternative was ignored by BPUB.

Moreover, the advantage of the reference case ($2,596,803 CPWC) and the transmission alternative ($2,525,341 CPWC) over the Tenaska alternative ($2,531,111 CPWC) or the Modified Tenaska Alternative ($2,394,369 CPWC) was the ability of BPUB to reduce or halt their expansion plans if variables such as gas prices, peak demand growth, and peak capacity needs were not what was originally projected in 2009, an outcome that was relatively assured by 2012.

6.1.2.3. Management Interference and Circumvention of Process

6.1.2.3.1. Contrived Capacity Shortage

Perhaps more so than any other factor, the driving force behind the 2011 IRP and the subsequent pursuit of the Project was the widely publicized impending capacity shortage described in the IRP. Yet, as noted in Section 6.1.2.2 above, B&V's peak summer demand forecast and projected capacity shortage was based entirely upon the Beck Forecast, a fact emphasized by B&V throughout the IRP as illustrated below:

> *"The load forecast utilized in this IRP was developed for BPUB by R.W. Beck, Inc. /SAIC in the 2009 timeframe. On the basis of the load forecast and existing generating resources, BPUB is projected to require additional capacity to satisfy its reliability criteria beginning in 2012...The need for future resources was determined on the basis of available existing resources and BPUB's projected peak demands through the 2031 planning horizon"*

Moreover, as B&V further pointed out, with the reliance on the Beck Forecast, the IRP focused on a single set of assumptions ignoring the impacts that changes to those critical input assumptions (Peak MW, fuel cost, and market power prices) would have on the evaluation of the expansion plans.

> *The need for future resources was determined on the basis of available existing resources and BPUB's projected peak demands through the 2031 planning horizon….the expansion plans in this IRP focused on a single set of input assumptions in this regard, consideration should be given to evaluating the potential impact of changes to various input assumptions (such as the load forecast, fuel prices, CO2 emissions allowance prices, and market power prices)."*[29]

In fact, B&V further acknowledged the "vintage" of the Beck Forecast and the lackluster state of the Greater Brownsville Area economy and suggested "consideration should be given to evaluating resource planning

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[27] 2011 IRP Section 2-5.
[28] Prior to the IRP's completion, it was known that ERCOT's Board of Directors had unanimously voted to endorse the Cross Valley 345kV Line Project. Thus by 2014, an additional 100MW of transmission capacity into the Brownsville area was expected.
[29] 2011 IRP Section 1-1.

decisions in light of sensitivities to these projected growth rates," i.e., <u>a reassessment of the growth rates should be undertaken before basing future resource decisions on those assumptions</u>. B&V communicated to Management prior to the December 21, 2011 Board Meeting that it considered the capacity needs in the Beck Forecast to be overstated due to the area economy.

Given that a utilities planning cycle typically consists of a load forecast, which projects future power needs, and an IRP, and given Management's plan to update its long-term load forecast every two years,[30] the use of a load forecast based on actual data from 2007 and prior years (2008 was estimated as described in Section 6.1.1.1 above), four years later is nonsensical and assures unreliability in the results.

Apparently, John Bruciak shares the same opinion regarding load forecasts. When asked about load forecasts and their reliability in his interview he stated:

> *"Those things (load forecasts) are as good as the day you published it, and they may be really accurate, some of them are. Most of them change"*

As discussed in Section 6.1.1.1, Beck emphasized the uncertainty inherent in the model and the need to periodically adjust the forecast. Beck even provided Management with the means to do so. However, B&V was not asked to incorporate this uncertainty into its IRP and adjust accordingly.

When asked why the forecast was not updated as recommended, Marilyn Gilbert[31], in her July 21, 2022 interview, denied that the forecast was not updated and claimed several times that B&V looked at the 2009 Beck Forecast and generated a new load forecast to reflect new data points. As discussed in detail below, these statements were obviously false. When CRI asked Mr. Bruciak why the forecast was not updated as recommended by Beck, Mr. Bruciak could not provide an explanation.

However, in our review of emails and documents pertaining to the IRP proposal, it was clear that B&V had initially proposed generating a new load forecast. That proposal was declined. In reviewing the IRP proposal[32] submitted by B&V, it was apparent that Management directed B&V to utilize the Beck Forecast as is.

> *"BPUB has requested Black & Veatch to utilize R. W. Beck's annual peak and energy load forecasts performed in 2009 for BPUB…For purposes of the cost estimate included in this proposal, it has been assumed that the R.W. Beck load forecast can be used without any changes."*

An email by Marilyn Gilbert on August 2, 2011 reiterated Management's intention, **"The R.W. Beck load forecast will be used without any changes."**

In using the Beck Forecast's Peak Demand as the IRP's driving factor, Management ignored nearly four years of historical data and its own policy, intentionally casting aside the opportunity to derive meaningful results from the studies for which BPUB paid substantial money.

In conjunction with the use of the outdated Beck Forecast, Management directed B&V to add an additional capacity reserve margin of 13.75% to the load forecast thus enhancing the perceived capacity shortage. The

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[30] Interview with Marilyn Gilbert.
[31] Her role as Energy Risk Manager, at the time of the 2011 IRP, included reviewing load forecasts and IRPs.
[32] B&V 2011 Integrated Resource Plan Update dated June 6, 2011.

effect was to add an additional 44 MW to the capacity shortage in 2012, 46 MW in 2013, 48 MW in 2014, increasing each year as the already overstated Peak Demand increased. Throughout the numerous presentations to the Board and the COB Commission, Management described this as an ERCOT requirement. During our July 21, 2022 interview with Ms. Gilbert, when asked about the ERCOT requirement for Load Serving Entities ("LSEs") such as BPUB she stated, "LSEs were required to have a reserve margin…ERCOT passes it along to the LSEs that they need to maintain certain requirements." Yet she could provide no definitive source for that information. In our interview with Mr. Bruciak thirty minutes later, we again asked about an ERCOT 13.75% capacity reserve margin requirement for LSEs. He stated that he understood that it was a "requirement that ERCOT [had]." He continued that BPUB was "carrying it not because we wanted to but we were because [of a] condition of ERCOT that they wanted you to carry [a reserve margin]." However, CRI has determined that the statements made by both Mr. Bruciak and Ms. Gilbert appear to have been intentionally false.

ERCOT, as the independent system operator for the region, did in fact use a 12.75% target reserve margin capacity internally <u>to manage the region's power needs</u> and had discussed increasing its margin to 13.75% around 2011. Yet, notwithstanding Management's false statements above, according to an ERCOT representative on August 5, 2022:

> *"ERCOT does not have a Reserve Capacity Margin requirement for LSEs. There has not been a change to no longer have a requirement for Reserve Capacity Margin.* ***There has never been such a requirement in the ERCOT market.*** [Emphasis added]*"*

Thus, BPUB, an LSE, had never and was not required to forecast or maintain a capacity reserve margin. In fact, the Beck Forecast did not include the reserve margin and, more importantly, subsequent IRPs in 2017 and 2020 removed the reserve from peak demand forecasts. It appears that the reserve margin's inclusion, at Management's request, was merely another means to artificially inflate the hyped capacity shortage even further in an effort to justify the Project.

6.1.2.3.2. Manipulation of the Process

In addition to developing the 2011 IRP, B&V's 2011 scope of work included developing and making presentations to Management and the Board, developing and circulating a Power Supply RFP, and evaluating the proposals submitted by responders.

In conjunction with its scope of work, on December 15, 2011, B&V submitted its presentation on the 2011 IRP update to Management for use in the 12/22 Presentation. In addition to summarizing the current IRP findings described in Section 6.1.1.2 above, B&V noted the following recommendations:

- **Issue All-Source RFP**
  - Any technology
  - Any location (delivery into Brownsville preferred)
  - Indicate desired capacity amounts and timing
  - PPA and equity interests
  - If located outside the Brownsville area, bidders must address deliverability including bidding cost of CRRs if appropriate

- **Compare RFP responses to Reference Case and Tenaska option**
  - Define criteria (economics, jobs, other non-price attributes)

- **Based on the above, develop two year resource specific action plan**
    - Only need to have an action plan that deals with current need for resources to meet target planning reserve margin.
    - Do not need an action plan next year to have wind on line in 2016. That action plan can be deferred until a 2014 update of IRP, which IRP can take into account what is known at that time.
- **B&V concluded:**
    - The Tenaska option looks like a good one on the surface. However, it is desirable to evaluate it against other potential bids. Hopefully an RFP can be performed in a timely manner that it can be completed before a final answer needs to be made to Tenaska. That will allow BPUB to demonstrate to its stakeholders that many bidders were considered and the best taken [emphasis added].
    - If Tenaska needs a decision before an RFP can be conducted, then BPUB needs to consider how it will make that decision given the "rushed" requirement.

In light of the foregoing, B&V clearly determined that the most efficient and effective course of action for BPUB was to solicit proposals from market participants so that BPUB would be able to evaluate the best possible approach to meeting generating needs. Moreover, as pointed out by B&V, since wind and inlet fogging would provide additional capacity by 2014, BPUB only needed to have a two-year action plan that deals with current need for resources. Given the uncertainty in the Beck Forecast, B&V was suggesting deferring long-term action until an IRP update in 2014 when the update can take into account what is known at the time.

This presentation by B&V was discarded by Management and replaced with a BPUB presentation that was biased toward the Tenaska proposal, removed key language and observations (Drivers of findings and renewables findings) in the B&V draft, removed B&V's observations regarding the Tenaska proposal, and watered down or reworded B&V's suggestions. As described above, B&V's scope included the development and circulation of the Power Supply RFP and evaluation of the proposals submitted by responders. According to BPUB's IRP Project Fact Sheet[33] updated February 17, 2012, B&V's remaining tasks consisted of the following:

Figure 5

Action Plan:
Present to the BPUB Board on February 27, 2012.
Request to proceed with RFQ process as delineated in Section 12:

Task 12 - Power Supply Request for Proposal (RFP) Development & Evaluation
- Task 12.1 – Gathering of Data and establish RFP Strategy
- Task 12.2 – Develop Power Supply RFP
- Task 12.3 – Develop Distribution List
- Task 12.4 – Participate in Pre-bid Meeting
- Task 12.5 – Review and Economic Screening of Proposals
- Task 12.6 – Detailed Evaluation of 10 or Less Proposals
- Task 12.7 – Financial Plan Update - Proposals
- Task 12.8 – Preparation of RFP Report Summary

[33] An internal BPUB document listing and tracking the Project steps and milestones.

While development and evaluation of the power supply RFP would have undoubtedly provided BPUB with the means to make the most economical decision relating to its power supply needs, such a process was not followed. In our review of 2012 documents and emails, we discovered that B&V did in fact draft the Request for Power Supply Proposals; however, the RFP was never released by Management. Instead, BPUB deemed Tenaska the best option in January 2012 and re-scoped B&V's contract to assess the Tenaska proposal using information provided by Tenaska.[34]

Interestingly, in addition to disavowing any opinion[35] on whether the Project was the least cost or most optimal project that could be developed, B&V also noted in the Tenaska Assessment that:

1. A June 2017 COD was likely, not the proposed June 1, 2016 timeframe presented by BPUB and Tenaska.
2. There were significant conditions precedent to Tenaska's continued development of the Project (aside from subscription), chiefly that the Cross Valley Transmission Projects would need to be completed.
3. The lack of off-takers of the Project's generation capacity (aside from BPUB) was restricting final development of the Project.[36]

Importantly, the same lack of transmission capacity that the Cross Valley Transmission Lines were designed to alleviate – and required for Tenaska to move forward – was also identified by BPUB and Tenaska as a reason to pursue the Project. Stated another way, BPUB and Tenaska cited the lack of transmission capacity into the area as a reason to push the TBGS while also requiring that new transmission capacity into the area be operational before the Project moved forward.

More importantly, as far back as May 2012, B&V emphasized its concern over Tenaska's ability to garner enough interest by prospective subscribers, a theme that resonated throughout the following six years.

Notably, prior to completion of the Tenaska Assessment, B&V was one of two firms awarded a power consultant contract by BPUB to assist with the Project, and also used to assist BPUB in determining whether the Project should go forward - a self-serving determination and potential conflict of interest. We noted that B&V's presentation on the results of its Combined Cycle Technical Assessment was dated after the solicitation by BPUB to propose on other contracts. The presentation omitted any negative or cautionary information including the language about off-takers restricting development of the Project.

CRI notes that when asked if the Power Supply RFP was ever released, Management first dodged the question then confirmed that an RFQ was produced and claimed the results were already provided. However, when pressed further by CRI, Management acknowledged that the "RFQ" it referenced was the RFQ for *power supply consultants***,** and the proposal results referenced by Management was the Tenaska

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[34] The results of the evaluation were presented in a study titled *Proposed Combined Cycle Technical Assessment* dated May 2012 (the "Tenaska Assessment").

[35] The technical assessment only evaluated whether the costs and characteristics were "reasonable" for a Project at that stage of development and whether it had "significant potential" to be developed – not whether it was the optimal choice for BPUB to pursue.

[36] Per B&V, the Project's development "hinges on Tenaska contracting with off takers for a significant portion of the Base Project's capacity...The identification of other off takers …will determine the size. configuration, and schedule for the Base Project and will likely determine if the Base Project ultimately moves forward."

Assessment produced by B&V, neither of which had anything to do with a power supply RFP and the evaluation of respondents.

Management had the opportunity to solicit proposals in order to make the most economical decision relating to its power supply needs. Given the above, it is our opinion Management repeatedly ignored the recommendations of its consultants, choosing instead to intentionally interfere in the process to ensure its desired outcome, the TBGS, was realized.

6.1.2.4. Misrepresentations and Omissions

6.1.2.4.1. Management's Control of the Narrative

According to the BPUB narrative, the 2011 IRP was the catalyst for the Project. BPUB confirmed this to COB auditor Patrick Zacchini in communications during his audit of the Project:

Zacchini: "B&V asserts their Integrated Resource Plan (IRP) in 2012 (it is dated February 2012) initially spurred the Project?"

BPUB: "True…"

In the 12/22 Presentation, one of the key issues noted by Management was the "IRP identified a capacity shortage." That was a misrepresentation, as the 2011 IRP document makes it clear that it did not determine the capacity needs. Those assumptions were taken from the Beck Forecast as requested by BPUB Management. The 2011 IRP merely took Beck's projected capacity needs and added 13.75% to the forecast at Management's direction. While there was a note in the 12/22 Presentation stating B&V believed that Beck's load forecast "was slightly overstated," the rest of the presentation focused on the capacity shortage and transmission constraints before moving on to a presentation on the proposed Project; the IRP status and recommendations were relegated to the final two slides. We found no evidence that the Board ever saw the draft 2011 IRP or draft B&V presentation.

While Management did relate to the Board that B&V thought the Beck's load forecast was overstated due to a slower economic recovery, that conclusion was not shared with the Commission. Instead, the Board requested "a more simplified version for presentation to the Commission and other key stakeholders…<u>try to make it much more simple; the term used was to make it a 5th grade level presentation.</u>"[37] Since BPUB has had difficulty locating presentations, we are unable to confirm exactly what information was shared with the COB at the first joint meeting related to the Project. However, at least one COB member present at the initial special meeting in early 2012, recalls a very short presentation of three to five slides highlighting a critical and immediate need (portrayed as an emergency) to add generating capacity. According to the Commissioner, there was no reference to B&V's opinion that the capacity shortage was overstated and the Capacity Reserve Margin was listed as a requirement. What BPUB did highlight was the increase in the amount of cash transferred to the COB as a result of rate increases.

This lack of any meaningful detail was prevalent in presentations made to the COB and, to a lesser extent, the Board. Throughout the life of the Project, we observed that Board and Commission members were often not provided with the full details of studies and presentations. Typically, members were shown an extremely summarized version highlighting the key points that Management thought were important or were aligned with their narrative.

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[37] Email titled [FW_ Special Board Meeting - Final 12 22 2011.pptx.pdf] dated December 23, 2011.

6.1.2.4.2. Other Interference

In our review of emails and meeting minutes and our discussions with previous BPUB members and COB commissioners pertaining to the origins of the Project, we noted the following:

- Mayor Tony Martinez, a member of the COB Commission and an ex-officio member of BPUB, was heavily involved with the TBGS Project before the Special Joint Meeting in May 2012 and may have exercised his influence over several commissioners prior to the May 2012 special meeting and again prior to the COB vote on the Project.
- As evidenced in the following email exchange between Mike Roth of Tenaska and John Bruciak, Management used its influence over certain commissioners to insure the smooth reception of the Project:

> *[Mike Roth – Tenaska] "Can you recommend another way to quietly inform the Commission prior to this meeting?"*
>
> *[John Bruciak – BPUB] "We can do that internally, and have the wheels greased"*

- References were often made by Mayor Martinez and John Bruciak to the city losing out on tremendous opportunities because companies didn't want to move to Brownsville due to lack of power generation capacity. However, according to sources in GBEC and COB, none of the cases cited were actually factual. There was no record of generation/capacity limitations being mentioned by a prospective business as a reason for not going through with development. In fact, prior to BPUB's decision to direct B&V to use the Beck Forecast, Management was using the Mayor to push the BEDC[38], a non-profit economic development group associated with former Mayor Martinez, to provide information on lost economic opportunities and to get a letter of intent from a steel company that was looking to locate in Brownsville. The intention was to use the prospective load to prop up the capacity needs since organic growth was not providing enough of a capacity shortage to justify a self-generating project like Tenaska.

> *"What we concluded is that we need to continue to work with BEDC to get a letter of interest from the Monterey steel folks to submit to ERCOT right away...The added load from the steel mill is critical in demonstrating load growth outside of organic growth models. Bill did not get a chance to visit with Jason about acquiring the letter from the steel folks. We need to somehow get the BEDC folks working on this while the initial BPUB/Sharyland study is being reviewed at ERCOT."*[39]

- The report touting the economic development impact of the TBGS,[40] released shortly after the signing of the Agreements, was allegedly commissioned by the BEDC. However, emails reveal the study may have actually been commissioned by Tenaska, a fact Bruciak was well aware of since he and Jason Hilts (BEDC President) were sent the report in a February 15, 2013 email by Mike Roth (Tenaska).

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[38] Brownsville Economic Development Commission had been contracted by the GBEC to assist in business development.

[39] August 19, 2011 email from Fernando Saenz to John Bruciak.

[40] Economic Impact of the Construction of the Proposed Tenaska Brownsville Generating Station by Aaron Economic Consulting, dated February 2013.

"Attached is the final Economic Impact Study that was completed by Dr. Malki at UT-B. My plan is to keep the full report within the bounds of our Confidentiality Agreements and will share the short version with commissioners and others. Holley is working on getting a press release put together."

6.1.2.4.3. Pre-Determined Outcome

The 2011 IRP, a study BPUB used to make major considerations about future capital projects, begins with the predetermined outcome that expansion is necessary. BPUB ensured this need by intentionally inflating the projected peak demand and resulting related capacity shortage through the use of an overstated peak capacity forecast and an artificial reserve requirement. While BPUB may never acknowledge the impetus of the Project, the objective may have been simply to drive a need for rate increases through capital expansion.

The business model of utility providers favors capital investment such as the Project. Texas utility code Chapter 36 Subchapter B Sec. 36.051 states:

"In establishing an electric utility's rates, the regulatory authority shall establish the utility's overall revenues at an amount that will permit the utility a reasonable opportunity to earn a reasonable return on the utility's invested capital used…"

Thus, utilities increase revenues by earning a rate of return on capital investments such as new power plants and other infrastructure. Anecdotally it would be unlikely that a municipality would allow a utility to increase revenue without evidence of a capital improvement to tie it to the increase, an opinion confirmed by a Commissioner. In other words, BPUB may not have been successful in getting a rate increase if they simply presented a need to support additional O&M costs.

Regardless of the future energy needs, there was clearly a bias towards a major expansion. This is in lieu of smaller opportunities available that would have supplied the area with the energy it demanded, but would have robbed the BPUB of the opportunity to greatly increase its economic position as it did with the rate increases stemming from the Project.

6.1.3. Conclusion

The IRP did not determine capacity needed, did not perform any analysis to determine if that forecast was still valid, and did not examine the underlying drivers of the forecast and compare to actual results over prior three years. Instead, at BPUB Management's direction, B&V used the Peak Demand from the 2009 Beck Forecast without changes and added a 13.75% reserve capacity margin. The resulting forecasted shortage was used by Management to demonstrate the need and push the Project forward.

We believe that the overemphasis of a capacity shortage that was artificially inflated was a key driver in the Board and COB approving this Project. When one considers the magnitude of the capital investment, it would have been prudent to make sure that all data sets and inputs are up to date and accurate and that the process to seek competitive proposals was performed. Yet, BPUB did not take advantage of its ability to review the Beck forecast on a monthly basis nor did it allow its independent engineer, B&V, to validate the accuracy of a key input to the IRP. Further, given the above interference and manipulation of the narrative and the overall process, it is our opinion that Management intentionally misrepresented or omitted key information in order to ensure that the Project (and its related rate hikes) would be approved by the Board and ultimately the COB.

6.2. PROJECT EVENTS AFTER JANUARY 2013

6.2.1. Background

After the Definitive Agreements were signed, and the Project was announced publicly, BPUB began to focus on its contractual obligations to the Project, as well as its plans to construct the Pipeline.

As previously stated, the Project was expected to have 800 MW of capacity with BPUB entitled to 25 percent of the capacity through either an undivided ownership share or a long-term purchase agreement. Tenaska was responsible for marketing the remaining 600 MW of the plant by November 2012. According to March 11, 2013 closed-session meeting minutes, Tenaska reported that it had market interest in over 500 MW statewide, and expected "to fully [subscribe] the remainder of the plant by May of 2013." However, the minutes do not reflect that an extension agreement was executed by Management that extended the subscription deadline to August 30, 2013. Since any Board discussions of the Project were conducted in closed session under the rules governing sensitive competitive matters, we believe this letter agreement to extend was not openly discussed with the Board.

In March 2013, BPUB selected engineering firms that would complete the required feasibility studies. Management shortlisted several firms and presented the proposed costs to the Board for approval. Ambiotec Engineering Group, Tetra Tech, Inc., Willbros Group Inc., and AECOM were awarded contracts to complete the studies associated with the Project and Pipeline.

Board members Vasquez and Najera, Management,[41] Board counsel Eddie Trevino, Mayor Martinez, Max Yzaguirre ("Mr. Yzaguirre"), and financial advisors Hinojosa Garza attended meetings in New York on March 7-8, 2013 with bond rating agencies to present information on COB, BPUB, and the Project. Moody's, one of the rating agencies, sent follow-up questions to BPUB regarding its TBGS strategy and the extra/excess capacity. Shortly after receiving responses, on April 1, 2013, Moody's released a stable outlook. Fitch however, downgraded the rating outlook from stable to negative. The rating agency listed concerns over the Project's impacts to BPUB finances as the driver behind the rating change. An ongoing concern was that once financing closed on the Project, Fitch would likely downgrade BPUB's bond rating.

During the April 8, 2013 meeting, Greg Kelly of Tenaska updated the Board on Tenaska's marketing efforts and noted the concern that off-takers may not need power until 2017-2018. At that time, the COD was expected to be Fall 2016. We noted that a letter was executed April 23, 2013 that formally extended Tenaska's subscription deadline to September 16, 2013; yet, there was no record of a vote in the closed session minutes.

In May 2013, BPUB approved the third extension for 60 days to allow Tenaska more time to find subscribers and to resolve EPA and other permitting issues. This extension moved the subscription deadline to November 15, 2013. Meanwhile, work on feasibility studies continued, and gas pipeline legislation was being considered on the state level.

An extension agreement dated July 26, 2013 defined the Critical Dates for performance under the various agreements (which included subscription deadline, Target COD, and Guaranteed COD). It also extended the critical dates by 60 days plus the number of days between July 31, 2013 and the feasibility study report dates. This allowed Tenaska additional time to complete subscription but also gave BPUB more time to

[41] BPUB CEO J. Bruciak, COO F. Saenz, and CFO L. Garcia attended on behalf of BPUB management.

complete the feasibility studies. The July 2013 minutes stated that further permitting issues would delay the Project another nine months, pushing the COD to spring 2017.

Throughout this delayed time, Mr. Yzaguirre gave regular status updates to BPUB in closed session stating that Tenaska was looking at specific entities[42] as "Tier I" prospects. During his update on April 14, 2014, Mr. Yzaguirre stated that Tenaska hoped to finalize subscription the following month, May 2014,[43] nearly one year after the initial expected subscription date. However, it is unclear how Tenaska would have been able to finalize subscription within one month of the update considering there was no mention of letters of intent nor MOUs in negotiation.

Not surprisingly, Tenaska did not have subscribers in May 2014. During the May 2014 closed session, the Yzaguirre update to the Board continued to reflect only a list of potential prospects for the remaining 600 MW. The expected financial closing was left unchanged – first quarter 2015, while the COD remained as spring 2017. Despite the optimistic timeline remaining in place, Board meeting minutes reflect that members and consultants had begun to voice concerns about the viability of the Project. More specifically, Current Board chair Noemi Garcia advised the Board that Noe Hinojosa, a financial advisor with Hinojosa Estrada, had expressed concerns.

Mr. Hinojosa's concerns related to the lack of subscribers, Project delays, and the mounting cost of the Project. Other than Hinojosa Estrada, we noted no consultants or Board members who expressed doubts about the Project's viability or progress directly to the Board.[44]

In the months that followed, Mr. Yzaguirre continued to report that Tenaska was working to market the plant, with an expectation that the remaining capacity would be subscribed in the fourth quarter of 2014. One prospect was expected to have a MOU in place by the end of August 2014 and another expected to make a decision in September.

Meanwhile, the permitting process that delayed the Project in July 2013 was moving along, with the air permit in place and the greenhouse gas permit expected to be approved in September 2014. Notwithstanding the additional time provided by the delay, Tenaska had yet to secure any subscribers.

BPUB's consultants had begun work on ROW acquisition in mid-2013 for the Pipeline. Initially BPUB counsel DTRG was handling the ROW acquisition, but BPUB elected to engage law firm Andrews Kurth, LLP to take over the process, despite objections from some Board members. By July 2014, condemnation proceedings were under way for landowners who did not accept their ROW offers; thus, there was a sharp increase in the condemnation proceedings budget.

Management proposed to the Board that the condemnation proceedings budget needed to increase from \$212,500 to \$960,000. Board chair Noemi Garcia expressed concern that the fees were excessive. Eddie Trevino, local Board counsel, defended the fees, stating that Andrews Kurth had to get familiar with the Project and had to duplicate work done by DTRG. At this time, the gas line feasibility study contract was

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[42] Through most of 2013 and 2014, CPS and STEC were regularly named as top prospects.
[43] Contractually, the subscription deadline was November 2013.
[44] Multiple sources have stated that Mr. Hinojosa and/or his associates were looked upon unfavorably for expressing doubt about the Project's viability and have suggested that they were excluded from future discussions about the Project.

also amended to include an additional $169,400 for add-ons to the scope of work. Through July 2014, BPUB had expended approximately $16.5 million on the Project. The majority of the expenditures were for engineering and legal fees.

In August 2014, the feasibility studies were presented to the Board. Per an email from Mr. Yzaguirre, the approval of the feasibility studies was one of the last exit ramps for BPUB.[45] The Board approved the feasibility studies, subject to Tenaska's satisfying or waiving its subscription obligations.

After the presentations and vote on the feasibility studies, the Board asked its financial advisors whether they had any comments. Mr. Hinojosa reiterated his concerns about Tenaska subscribing the remaining 600 MW. He also mentioned that rating agencies could frown upon a merchant plant, should Tenaska decide to operate the plant without subscribers. Estrada Hinojosa presented its finance plan for the Project in August 2014, but no action was taken by the Board.

During the October 28, 2014 meeting, Mr. Yzaguirre presented the final version of the omnibus extension agreement that he had initially discussed in August. As noted previously, the Board voted to approve the feasibility studies, subject to Tenaska's "satisfaction or waiver of Tenaska's subscription condition."[46] A presentation of the agreement included the bulleted points below:

- Tenaska is waiving its subscription condition simultaneously with BPUB's waiver of its feasibility study condition (i.e., BPUB succeeded in linking BPUB's approval of the feasibility studies to Tenaska's subscription condition, instead of BPUB being the first to waive its condition without a concurrent Tenaska waiver).
- A mutually agreed procedure to ensure cooperation during the financing phase was added.
- Tenaska agreed to pay 75% of BPUB's development and construction costs for the water and wastewater infrastructure. The development costs will be paid upon financial closing, and the construction costs will be paid as incurred and billed directly to Tenaska, except that Tenaska will pay for 75% of two of the development cost items (totaling up to approximately $1.9 million) independently of financial closing. Tenaska will have the right to approve infrastructure design, open-book contracting, and the bidder's list and, to the extent permitted by applicable law, Tenaska or its designee will be permitted to bid as a potential contractor.
- BPUB to obtain water supply and wastewater discharge right-of-way prior to financial closing.

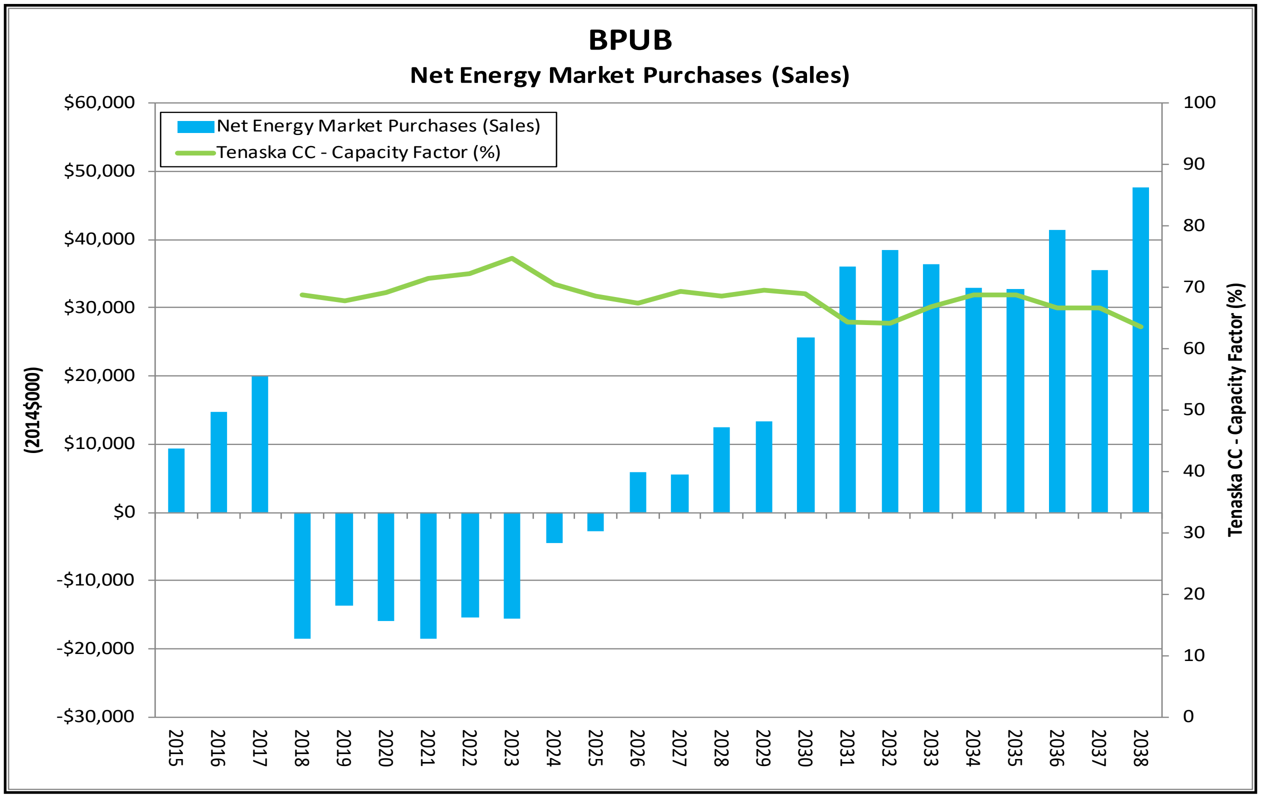
In addition to the above provisions, there were agreements that Tenaska would contribute to the costs of compression for the gas pipeline, pay an extra $0.11 per thousand gallons of effluent, and advance any ROW payments above $250/rod, to be repaid from future gas revenues. BPUB consultants presented to the Board that the omnibus agreement provided a total value of $14.1 million - $16.5 million. This value could only be realized, however, if the Project went to financial close and/or construction.

During this same October 2014 meeting, B&V presented the results from its "Generation Reliability and Retirement" study. B&V concluded that existing BPUB units were in good condition, with life expectancies ranging from 22 to 40 years. The presentation to BPUB also included a slide comparing the long-term production cost of the Project with a smaller self-build option, the results of which reportedly showed that production costs would be $5 million to $10 million lower with the Project.

[45] Exit ramps were provisions built into the Definitive Agreements which granted parties the unilateral right to exit the Project without legal penalty.
[46] August 7, 2014 BPUB closed session minutes.

In addition to the reported production cost savings, B&V noted that without the Project, BPUB would face increasing risk exposure to potential increases in market prices. With the Project however, B&V projected that BPUB would be a net seller in the wholesale market, as illustrated in the following figure:

Figure 6



B&V Generation Reliability and Retirement presentation

Overall, the presentation showed that the Project was more beneficial than a smaller plant and would meet BPUB's future needs that were projected in the previous IRP and load forecasts that were the catalyst for the Project. However, once again the circular logic employed by B&V and Management to continue to promote the Project was apparently lost on the Board. B&V reasoned – incorrectly – that it was less risky for BPUB to participate in a project that had to sell 800 MW in market that already had an oversupply of capacity than it was for BPUB to purchase capacity in a market where there was an oversupply that drove down spot market prices.

At the following meeting in November 2014, Mr. Yzaguirre reported that Tenaska was considering alternatives to the 800 MW plant. Even though there was allegedly a prospect that was expected to make a decision on a purchase of up to 500 MW of the plant in January, Tenaska proposed two backup plans. The Plan B suggestion was a merchant plant option, where instead of long-term subscriber contracts, Tenaska would compete to sell the excess capacity on the open market. Plan C would be to construct a smaller plant. The new expected financial close would be March 2015. The minutes stated that the Board "continues to question the delay of the Project," and that these issues would be addressed by January 2015.

At the February 9, 2015 meeting, representatives from Tenaska notified the Board that the major prospect expected to make a decision on subscribing up to 500 MW in January was now on indefinite hold. The projected financial close was now expected to be in July 2015, and COD would be July 2018.[47] Subscribing the remaining power to the prospect was Tenaska's Plan A. Having been unsuccessful in finding a subscriber, Tenaska informed the Board that it was proceeding with Plan B: a merchant based financing plan. Minutes do not reflect any objection by BPUB to the merchant based financing option, despite the fact that in August 2014, its financial advisor voiced his concerns that bond-rating agencies may frown on a merchant plant. Tenaska also stated that it is considering a Plan C – building a smaller plant, "reaffirmed their commitment to the Project,"[48] and would provide updates leading up to the scheduled March Board meeting.

When Tenaska representatives returned to the Board on March 27th, Tenaska discussed its alternative plans for the plant. The options were:

- Plan A: A fully subscribed 800MW combined cycle generation facility.
- Plan B1: 800 MW plant with the excess 600MW capacity marketed as a merchant plan with hedges and external equity
- Plan B2: 400 MW plant (that could be expanded in the future) with the excess 200 MW capacity following the merchant plan
- Plan C: Smaller right-sized plant with expansion potential.

Tenaska presented the Plan B option to lenders in New York, and minutes reflect that lenders liked the Project but the response was short of Tenaska's expectations.[49] Despite their most likely prospect putting subscription plans on hold indefinitely in January, Tenaska touted that it was still pursuing the prospect with a "right sized" proposal.

Tenaska again highlighted its substantial financial investment in the Project and reiterated its commitment. Tenaska also informed the Board that for the previous two years the market had needed to improve, meaning that gas and electricity prices were low and conditions were not advantageous[50] for subscribing the plant but BPUB was currently benefitting from the lower rates.

Knowing this, Tenaska continued to state that the COD was still likely summer 2018. The Board expressed concerns and questioned how the public should be educated going forward. The Board also questioned whether it should defer current rate increases. At the time, two scheduled rate increases remained - October 1 2015 and 2016 - from the 2012 rate increase ordinance[51]. While we do not know what was discussed

[47] Meeting minutes specifically state "commercial operating date is **still** [emphasis added] second quarter 2018 (July)". This may be a typo as the last COD presented at the November 10, 2014 meeting stated July 2017, though 2018 would be the more likely date.
[48] February 9, 2015 closed meeting minutes.
[49] Financial advisor Noe Hinojosa reported to the Board in August 2014 that he believed rating agencies would frown upon a merchant option.
[50] When prices are low, it is a "buyer's market" meaning that providers can purchase their power needs on the market at competitive prices instead of locking themselves into fixed long-term rates through subscriptions or Power Purchase Agreements.
[51] According to BPUB documents presented to the COB in August 2020, the Tenaska equity fund allocation set aside for debt service was $19 million in fiscal year 2015 and the annual recurring revenue increase from the Tenaska portion of rate increases was $8.6 million.

with respect to proposed rate increases, we can infer from later rate increase discussions that the Board was advised the increases were necessary to insure that funding was in place to cover BPUB debt service obligations[52] in the event of financial close of the Project. In the end, the Board agreed to be patient going forward.

In June 2015, the Board unanimously approved a time extension agreement[53] which extended the critical dates on a day-to-day basis by the number of days equal to 360 days, plus the number of days between May 1, 2015 and the date on which either party provides written notice to terminate the automatic extension. After which, both parties would work together in good faith to draft a revised schedule of the critical dates.[54] As consideration for BPUB's agreement to the extension, Tenaska would pay BPUB a monthly sum of $35,000.

Closed session minutes from June 15, 2015 reflect a discussion of the $35,000 monthly fee, which was to be paid to The Yzaguirre Group for consulting services. Mr. Bruciak noted that Tenaska wanted to engage The Yzaguirre Group to assist with negotiations in Mexico with respect to whether the government-owned utility there would be a willing provider. Following the approval of the time extension agreement, Mr. Yzaguirre attended two additional meetings in 2015 to provide updates on marketing efforts in Mexico.[55]

On November 9, 2015, the COB informed Mr. Bruciak, Mr. Garcia, and Mr. Hinojosa that the Commissioners requested an agenda item to discuss the rate increases be added for the next Commission meeting. Internally, Mr. Bruciak and Mr. Garcia questioned the need to have a meeting discussing the rate increases. Specifically, Mr. Garcia recalled that they had met individually with the COB commissioners months prior and reviewed the rate increases.

The Commission held a meeting on November 17, 2015. BPUB representatives presented a recap of the utility rate increases, the rationale for the increases, an overview of the Project, and a financial update. The executive session presentation included Project-specific information, including an update on capacity forecasts, an overview of the Project and its current status,[56] BPUB financial plans, and a history of the city transfer. It appears that the executive session presentation led to more concerns from the Commission.

Months later, in February 2016, Commissioner John Villareal initiated a conversation about the COB's obligation to maintain the rate hikes based on information presented in the November executive session. From meeting minutes and email discussions, it was apparent that residential customers were concerned about the higher utility rates as well.

In response to pressure over high utility bills, BPUB proposed a plan at the April 2016 meeting to lower customer bills by using surplus Project equity funds to stabilize the Fuel Purchase and Energy Charge at $0.029 per kwh until the Project became operational. Historically the FPEC charge fluctuated between

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[52] BPUB management's objections to rate rescission are discussed in a later section of our report.
[53] Extension agreement executed June 29, 2015
[54] BPUB and Tenaska could mutually agree to extend the critical dates beyond the agreed upon schedule set forth by the letter agreement.
[55] Mr. Yzguirre briefed the Board on August 10, 2015 and September 14, 2015, while he was employed by Tenaska.
[56] The presentation stated that financial close was currently pending and subject to subscription progress and market condition improvements, but anticipated to occur during the latter part of 2016.

$.07 and $.032 over the previous 10 years. The Board agreed, and for several months there was little to no Board discussion of the Project.

A few weeks prior to the August 2016 Board meeting, Tenaska representatives met with Management[57] to discuss the status of the Project, the potential for a "Plan C", consultant The Yzaguirre Group, and other agenda items pertaining to the Pipeline. It is noteworthy that there was no mention of this meeting in the August 2016 Board meeting nor subsequent meetings.

Although there was no discussion of the Project and the rate increases in Board closed sessions for the remainder of 2016, internally there was a flurry of emails among Management, financial advisors, and attorneys in late August and early September addressing potential Commission requests to rescind the final rate increase in October. Mr. Yzaguirre[58] also provided Management with a draft of message points and an overview of the Project in preparation for anticipated COB commission questions. It does not appear that the Commission pressed BPUB in session to rescind the October rate increase. Meanwhile in November, Tenaska requested that the 10-year tax abatement agreement with Cameron County be terminated, citing the market structure making it extremely difficult to build new facilities. In January 2017, Tenaska discussed the tax abatement cancellation with the Board, and stressed the need to for patience to see the Project through to fruition.

In April 2017, a joint meeting was held with COB where several commissioners expressed concerns about the lack of progress. After Commissioner Longoria stated that he wanted out of the contract, Mr. Davidson advised on the options to exit the contract. Mr. Bruciak part recommended waiting for the 2017 IRP results, which would address projected load growth and changes in the market.

B&V completed the 2017 IRP draft on May 1, 2017. The results of the IRP were presented to the Board during the May 8, 2017 meeting. The PowerPoint presentation showed that B&V rated the Project as the most economic option for electric generation expansion followed by other alternatives,[59] the least of which was a self-build generation facility. B&V recommended that BPUB continue to monitor market conditions and secure RFPs to evaluate other PPA options. BPUB could not consider any potential traditional (i.e. non-renewable) electric generation options with third parties due to contractual restrictions with Tenaska.

During that meeting, Fernando Saenz gave a "Power Supply Decision Timeline" presentation that provided a timeline of conditions leading up to the Project and a review of decisions made from Project initiation through 2017. Of note was a large drop in energy demand in Texas in 2014 and little to no growth through 2017.

On July 10, 2017, one day before the Commission meeting, BPUB held its regular Board meeting where a rate rescission vote was on the agenda. During the closed session discussion on potential impacts of the rescission, Mr. Garcia explained to the Board that a rescission would not allow BPUB to be an owner in the Project due to inadequate debt coverage. Mr. Garcia also advised the Board that residential customers would not see an impact in their utility bills because the rate stabilization program would have to end, causing an increase in the fuel surcharge. He also noted that the city transfer would be reduced by approximately $1.5 million.

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[57] Mr. Bruciak does not recall this meeting and therefore could not provide details of the agenda items discussed.
[58] Mr. Yzaguirre was still employed by Tenaska at this time.
[59] The other alternatives included wind and gas PPAs from suppliers in the market.

At the July 11, 2017 joint COB meeting, Mr. Saenz presented a different version of his Power Supply Decision Timeline presentation. The presentation culminated with the current stage of resource planning, the 2017 IRP, which was presented to the Commission showing the same ranking of power supply options as the Board's presentation. The Commission remained skeptical, with Commissioner Ben Neece questioning BPUB on how they might exit the agreements. Local counsel Eddie Trevino and DTRG attorneys explained that after giving notice to end the extensions, Tenaska would have one year to begin construction or both parties could exit the agreements. According to the minutes, the commissioners were advised that an early exit would cause BPUB to lose approximate $8 million in Tenaska reimbursements for development costs.

The following October, a meeting was held among Tenaska, Board members Galonsky and Vela, John Bruciak, Fernando Saenz, Leandro Garcia, Mayor Martinez, Conrad Bodden and DTRG representatives. The meeting took place in DTRG's offices in San Antonio. BPUB wanted to emphasize that they had lost patience and wanted information on Tenaska's ability to proceed with the Project. Tenaska indicated that it would not be able to negotiate an agreement with Mexico by January 2019.[60] BPUB determined that it would need to make decisions on whether to terminate the automatic extensions, terminate the water agreement, or negotiate better terms. The Board was briefed on the San Antonio meeting with Tenaska at the next regular BPUB meeting, November 13, 2017.

The Board took no action during that November meeting but wanted to know what its options were going forward. During the next meeting in December 2017, DTRG presented BPUB with its options and the possible outcomes. The options were:

- Do nothing, and stay the course
- Terminate the entire agreement
- Terminate the water agreement only
- Terminate the automatic extensions
- Terminate the water agreement and the critical dates extension

The Board voted unanimously to terminate the water agreement and the critical dates extension on December 17, 2017.

A timeline of key events after the Definitive Agreements were signed is outlined in Table 3 below.

[60] If BPUB gave notice to terminate automatic extensions in November 2017, Tenaska would have to be ready for financial close January 2019.

Table 3

Timeline of Project after Definitive Agreements Signed

Date	Event	Notes
1/25/2013	Definitive Agreements executed	Contractual Subscription Deadline July 15, 2013
3/11/2013	BPUB Closed Session	Tenaska expects to have plant subscribed by May 2013
3/20/2013	Extension Agreement executed	Subscription Deadline August 30, 2013, Not discussed in minutes
4/23/2013	Extension Agreement executed	Subscription Deadline September 16, 2013, Not discussed in minutes
5/21/2013	Extension Agreement executed	Subscription Deadline November 15, 2013
7/26/2013	Extension Agreement executed	Extend Subscription 60 days plus no. of days to complete Feasibility studies: January 21, 2015
10/28/2014	Omminus Amendment executed	Financial Close July 1, 2015, Tenaska agrees to additional cost reimbursements most tied to construction start
2/9/2015	Board Meeting	Yzaguirre informs board that the most promising subscription prospect put any plans of subscribing on indefinite hold
3/27/2015	Tenaska presentation to board	Edited to be less explicit in project shortcomings. Projected close Summer 2015, an unlikely date
6/26/2015	Agreement Extension	Automatically extends deadlines. Allowed Tenaska to hire BPUB Consultant Yzaguirre.
10/1/2015	Penultimate rate increase goes into effect	Project was on indefinite hold due to ERCOT market conditions
11/17/2015	COB Executive Session on Rate Increases	BPUB tells COB that project expects to complete by 2018. Promotes overestimated capacity shortage with 2011 IRP graphs completed with 2007 data. BPUB emails indicate Management met with individual commissioners on rates in August.
4/11/2016	Board approves rate stabilization program	Lowers FPEC to adjust avg. residential bill to $102. New FPEC is artificially low to make up for high utility rates. Easier to rescind and reallocate funds than get a rate increase approved.
7/21/2016	Tenaska provides timeline *if* Mexico goes well	COD wouldn't occur until 2022.
10/1/2016	Final rate increase goes into effect	If COD were known, the rate increase could have been deferred.
4/1/2017*	Management and Mayor meet with Tenaska	Tenaska indicates that they aren't going to build.
4/17/2017	Tenaska terminates contract with Yzaguirre	Signal that negotiations in Mexico are stalled or dead.
4/24/2017	2017 IRP Draft seen by management	Draft shows Project is not the most economic choice.
4/24/2017	Joint COB Session	COB told Tenaska is still actively marketing in Mexico. Mgmt recommends waiting for IRP before deciding on rate rescission or terminating project.
5/1/2017	BPUB receives final draft of 2017 IRP	Tenaska is ranked 4th on list of most economic generation options.
5/8/2017	BPUB presents IRP to Board	Tenaska is ranked 1st on list of most economic generation options.
7/10/2017	Joint COB Session	Same IRP results as presented to Board with Tenaska ranked as #1. COB told that early exit would cause a loss of $8M in reimbursements. Most reimbursements were tied to construction and financial close.
10/30/2017	Management, Board reps, and Mayor meet with Tenaska	Outcome was not positive. BPUB reports to board who then considers options to terminate.
12/17/2017	Board votes to terminate auto extensions	Starts the clock for Tenaska to build or terminate agreements.
2/8/2019	Tenaska terminates APA	
2/4/2020	BPUB terminates final agreement	BPUB waited until the last day to terminate. Advice from DTRG was to keep waiting in order to protect ROW proceedings. Could have terminated the previous August.

6.2.2. Findings

6.2.2.1. Management Influence

Management had direct influence on several presentations made before both the Board and the Commission. In many cases they omitted pertinent information that would have jeopardized support for the Project. In other cases, they outright changed facts to create a false narrative.

6.2.2.1.1. March 27, 2015 Tenaska Presentation

As described above in Section 6.2.1 Management and Tenaska representatives gave a presentation before the Board on March 27, 2015 addressing the Board's concerns regarding delays in moving the Project forward. In our review of emails and presentation drafts, we noted discrepancies in the version provided to Management by Tenaska and the version that Management approved for the Board presentation as detailed below.

The version presented to the Board included one basic slide stating the following Plan options:

- Plan A: Fully subscribed 800 MW 2x1 combined cycle facility
- Plan B1: 800 MW 2x1 facility with the excess 600MW capacity marketed as a merchant plan with hedges and external equity
- Plan B2: 400 MW plant (that could be expanded in the future) with the excess 200MW capacity following the merchant plan
- Plan C: Smaller right-sized plant with expansion potential.

The Board version also included an overview of STEC, its most promising prospect, including the current RFP status (on-hold) and Tenaska's intention to pursue a new proposal offering a strategy that fits with STECs generation needs based on a later start date and small amount of generation.

A graph illustrating 10-year forecasts of the ERCOT region's MW capacity, demand, and reserves was followed by Tenaska's plan for moving forward – patience, market improvement, and reiteration that the combined cycle plant is still the right plant to build but Plan C was listed as a backstop. Tenaska must have anticipated the Board's likely questions as several questions pertaining to the lack of interest, the ERCOT market, and potential public messaging were proactively placed in the final slides. However, none of the questions had answers.

When reviewed in conjunction with the meeting minutes, it was apparent that intended takeaway from the presentation was that Tenaska had substantial financial investment in the Project and reiterated their commitment. Moreover, the presentation pointed out that during the delay BPUB benefited from the current low cost of energy and the COD was still likely Summer 2018.

With regard to the original version drafted by Tenaska, we noted that it was sent to Fernando Saenz by Mike Roth the morning of the meeting with a message to use the presentation as a draft and "review with the group." The presentation was very detailed in explaining the realities of the Project's status and its obstacles.

The details of the alternative plans outlined in the Board version were fully discussed in Tenaska's original presentation. Tenaska presented the Plan B option (merchant plant) to lenders in New York and reported that four out of five lenders responded to their proposal, but interest rates were high, and the terms were unfavorable. The closed meeting minutes only state that the terms were short of Tenaska expectations.

Tenaska also highlighted the smaller economies of scale[61] with the smaller facilities proposed in plans B' and C. Plan C would have also required revisions to the Air permit and interconnection plans, thus increasing costs and delaying the COD. None of these details was in the final presentation.

The biggest omission however was in the "Questions" portion of the presentation. Here, the answers to the anticipated questions were included in the presentation. Of importance, when asked what can we tell people about the status of the Project? Tenaska's response was:

> *"Be honest. [Tenaska and BPUB] are partners in bringing the Project to Brownsville and will continue to work until the Project is complete. It may take some patience but we'll get thru it. Again, we have spent more than $20M on the development of the Project and aren't going to see it fall short."*

One question was left out of the presentation entirely:

> *Q: "Why Can't Tenaska just make this plant happen?"*
>
> *A: "We must be prudent and patient with our investment capital just like BPUB must be prudent and patient with the ratepayer money.* ***The truth is that the market is not right for this Project to go forward right now. We need a good long term decision rather than a bad short term decision*** [emphasis added]*."*

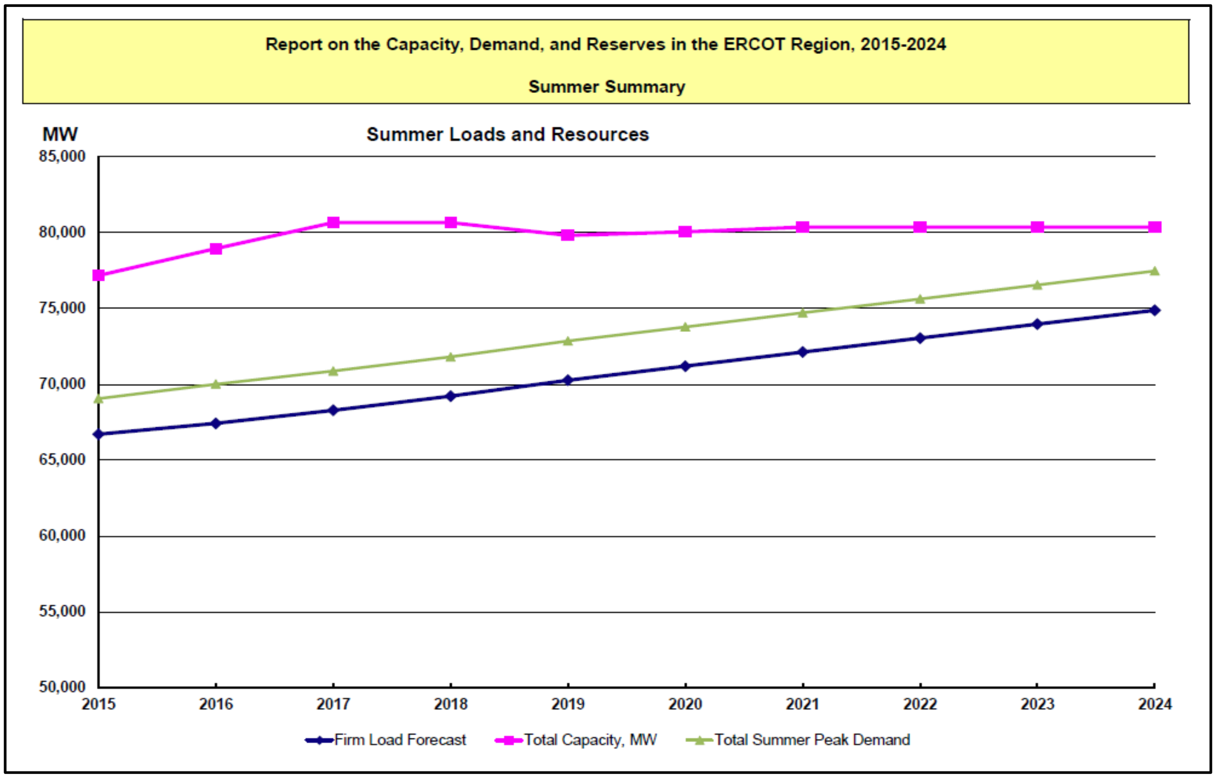
Clearly Tenaska was being fairly explicit in letting the Board know that the Project was put on an indefinite hold. Instead, the minutes reflect that the Board was told that a COD of summer 2018 was still on the table. Any talk of an indefinite postponement of the Project was kept off the table. As noted previously in this report, that 2018 COD was highly unlikely.

Based on previous Project timelines it would realistically take three to four years to get the Project built and in operation. Before any construction would take place, Tenaska would need to get to financial close with lender funding in place. In the most optimistic timeline that would have needed to occur Summer 2015, less than four months after the March 27 presentation.

Achieving a Summer 2015 financial close would have been practically impossible but was even more remote give the excess capacity in the ERCOT market, as illustrated in the presentation and duplicated in Figure 7 below.

[61] i.e. The unit cost of production was more expensive when overall production size was smaller.

Figure 7



Tenaska BPUB Presentation March 27, 2015

Given the excess capacity, it was clear that the ERCOT market would not support new generation facilities for several years to come. Had the Board been told that the Project was on hold until the market improved in conjunction with presenting the chart above, it would have been obvious that the projected 2018 COD was an illusion.

In addition to finding subscribers in a soft market Tenaska and BPUB would have needed to finalize plans on the plant size. Yet, internal communications demonstrate Tenaska was resistant to building a smaller plant. If they did agree to a smaller plant there was the potential that permits would have needed to be revised. Given the clarity of the original presentation and the ambiguity left in the final draft we have concluded that Management's edits to deliberately cloud the Project's status were at best a misrepresentation or, more likely, intentionally misleading.

6.2.2.1.2. November 17, 2015 COB Executive Session

In November 2015, the Commission requested that BPUB present information on the Project in response to growing concerns and questions about the status of the Project from commissioners. Specifically the COB required answers as to why the rate increases were originally needed and why they were still necessary. Management was confused as to why the COB would call upon BPUB to defend their rate increases. In a November 9, 2015 email exchange about the request John Bruciak questioned the need for the meeting and replied to Leandro Garcia:

> *John Bruciak: "When we met individually with the Commissioner a couple months back I thought we reviewed the rate increases.."*

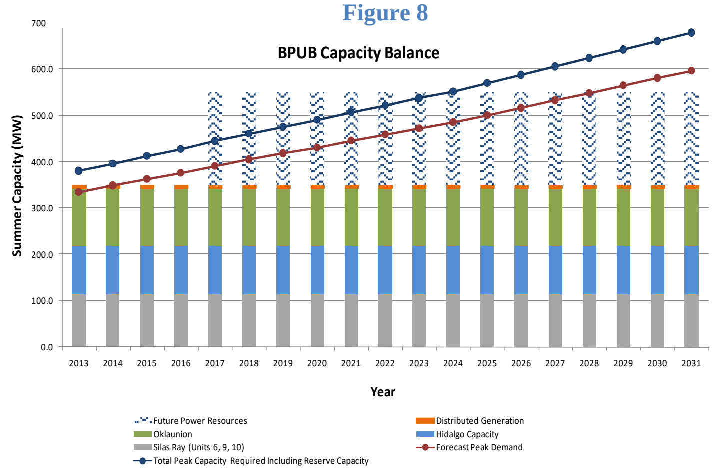
Leandro Garcia: "Yes, we covered the rate increases with all of them. Not sure what's up with the new request."

When Mr. Bruciak was interviewed about meeting with Commissioners individually before meetings[62] he replied that he never did so. He said on occasion one may give him a phone call about something that happened in one of their districts but normally he went through the city attorney or met with the full Commission. To the contrary, in addition to the email excepted above, one Commissioner recalled a meeting with Mr. Bruciak where he addressed the rate rescissions and discussed why the Tenaska rate increases should remain. It should be noted that if Management met with enough commissioners to represent a quorum while trying to influence the rate rescission vote, they may have violated state or local laws.

On November 17, 2015, Management attended the meeting in closed session and presented their PowerPoint presentation recapping the rate increases, addressing why BPUB needs more power, and providing the commission with an overview of the TBGS, and a financial update. In our review of the information presented and the narrative depicted by Management observed discrepancies and misrepresentations, the details of which are described below.

The presentation included a slide titled "Why does BPUB Need More Power" which featured a chart from the 2011 IRP, captured in Figure 8 below, that depicted the now well-known capacity shortage.

Figure 8



However, it's now the end of 2015 and the Peak demand (which usually occurs during the summer or less frequently in the winter months of Jan-Feb) for the previous three years would have been known. Yet, Management continued to present a chart with the headline, "Based on Black & Veatch's (B&V) Integrated Resource Plan of 2012 a projected capacity short-fall begins in 2013."

Notwithstanding the misrepresentation regarding the IRP's projection of a capacity shortage, the use of outdated capacity projections based on pre-2008 data and a reserve that wasn't required[63]appears to be an effort to intentionally distort or misrepresent the actual capacity needs of BPUB.

The following slide, titled *System Overview – Electric – Peak Loads & Resources (MW)* muddies the water even further.

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[62] The specific meeting in question was not the November 15, 2015 meeting discussed in this section of the report.

[63] We established earlier in our report that the reserve capacity was of BPUB's discretion and not an ERCOT requirement as previously stated by BPUB management.

Table 4

	Fiscal Year End (9/30)									
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Available Resources:										
Oklaunion Unit No. 1	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0
Oklaunion Unit No. 2	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0
Silas Ray Units	124.0	124.0	114.0	114.0	114.0	115.0	115.0	115.0	115.0	115.0
Sendero Wind Energy						0.0	34.0	34.0	34.0	34.0
Hidalgo	105.0	105.0	105.0	105.0	105.0	105.0	105.0	105.0	105.0	105.0
Distributed Generation	11.0	11.0	7.5	7.5	0.0	0.0	0.0	0.0	0.0	0.0
Planned Generation: Tenaska	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	200.0	200.0
Total Resources	364.0	364.0	350.5	350.5	343.0	344.0	378.0	378.0	578.0	578.0
Peak Load Responsibility:										
System Peak Demand	277.0	301.0	294.0	286.0	284.0	333.8	343.8	354.1	364.3	374.7
Reseve Margin %	13.75	13.75	13.75	13.75	13.75	13.75	13.75	13.75	13.75	13.75
Reserve Requirements	38.0	41.0	40.0	39.3	39.1	45.9	47.3	48.7	50.1	51.5
Total Requirements	315.0	342.0	334.0	325.3	323.1	379.7	391.1	402.8	414.4	426.2
Balance Available	49.0	22.0	16.5	25.2	19.9	-35.7	-13.1	-24.8	163.6	151.7

The table, replicated as Table 4 above, shows actual peak demand for the years 2010 – 2014 with the addition of the previously discussed reserve margin. The second half (shaded in blue) beginning in 2015 reverts back to the previous flawed capacity projection from the 2011 IRP.

Also notable is the jump of 56.6 MW that Management was projecting between 2014 and 2015 in the "Total Requirements" row (boxed in red), even though the 2015 peak was already over and it was only 286 MW. Clearly, Management was claiming BPUB would need 333.8 MW to cover peak demand in 2015 (379.7 MW with the reserve margin), even though they knew at the time that the 2015 Peak was 286 MW. In fact, the actual demand was steady, with the exception of 2011,[64] with demand ranging from 294 in 2012 down to an average of 285 MW in 2013 – 2015.

The presentation also contained misleading information about the status of the Project timeline. The table above reflects the planned generation from the Project (200 MW) was presented as being available in 2018. To the contrary, as discussed previously in this report, in order to have a COD of mid-2018, <u>under the most optimistic conditions</u>, financial close would need to occur no later than mid-2015. Yet, the year was almost to a close and Tenaska had not secured a single subscriber aside from BPUB. The presented COD is even more misleading when you consider that in another slide, Management specifically stated:

> *"Projected financial close is currently pending and subject to subscription progress and market condition improvements* ***but anticipated to occur during the latter part of 2016*** *[emphasis added]."*

In reality, a late 2016 financial close would make COD in 2018 not even a remote possibility, a fact Management was well aware.

Also notable in the presentation was the rate comparison. BPUB's average residential electric bill for the twelve months ending September 2015 based on 1000 kWh was $111.98, the 3rd highest of 13 retail electric providers and the highest of the eight presented municipal utilities. Moreover, BPUB's average residential

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[64] There was a winter storm in February 2011 which brought extremely cold temperatures and a surge in energy usage as a response.

electric bill for the twelve months ending December 2012 was $86.66, an increase of $25.32 or 29.2%. This outcome is a far cry from the statements made by BPUB and Mayor Martinez in promoting the Project where it was said COB citizens would see low rates.

> *Mayor Tony Martinez described the proposed power plant as "a terrific deal for Brownsville." "It ensures our energy needs for a long time. It ensures that you're going to have low rates."*[65]

Finally, as observed by CRI in every BPUB presentation to the COB, Management ensured that the presentation also highlighted the amount of cash transferred to the city, which served as a reminder to the COB that the rate increase directly affected the COB budget.

We asked Mr. Bruciak directly about the aforementioned graph using the R.W. Beck projections in 2015, even though actuals were known. His response was that he could not comment on the presentation because BPUB did not put it together. He claimed the presentation was compiled by Estrada Hinojosa. But, as financial advisors, they merely provided the sections pertaining to the financial update, debt service, credit ratings, and other information related to financial matters. In addition, notwithstanding Mr. Bruciak's claim, throughout our investigation we noted that a presentation was never presented or provided on BPUB's behalf without Management's review, input, and approval, and, more often than not, Management's direct revisions, prior to presenting it to the Board, the COB, or other outside parties.

Given the above, it is our opinion that both Mr. Bruciak's statement to CRI and the presentation to the Commission were intentionally misleading. The misrepresentations reflected in the presentation were just another notable example of Management's efforts to control the narrative and promote the Project at all costs.

6.2.2.1.3. 2017 IRP

In April 2017, the pending 2017 IRP was used to temporarily forestall the Commission's inquiries, with Management and DTRG stating that the COB should wait for the results, which should be available the following month. Black and Veatch completed the 2017 IRP on May 1, 2017, though a draft was emailed to Management on April 24th for review and comment. The results of the IRP were presented to the Board by B&V during the May 8, 2017 meeting. The PowerPoint presentation briefly listed the key assumptions (particularly, peak load growth of 1.05% per year[66]) and compared the near term capacity needs to those expressed in the 2011 IRP, which reflected a significant reduction, a result of more realistic assumptions and the removal of the 13.75% reserve margin.

The May 8, 2017 presentation of the 2017 IRP study results lists the Project as the best case scenario.

Similar to the 2011 IRP, the rankings were based on CPWC and presented the Project as the most economic option for electric generation expansion followed by the other three alternatives listed in Table 5 below.

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[65] BISD Presentation on August 6, 2013.

[66] As a comparison, the peak load growth utilized in the 2011 IRP, taken from the 2009 Beck Forecast, was 4.3% through 2018 and 3.1% from 2019 to 2032.

Table 5

CPWC Ranking from Lowest to Highest

EXPANSION PLAN	CPWC ($ MILLIONS)	RANK	COMMENT
200 MW BPUB ownership of Tenaska Plant	$1,004	1st	Development by Tenaska subject to favorable market conditions. BPUB will participate in ownership with Tenaska.
Wind PPA + 115 MW PPA from existing ERCOT combined cycle	$1,059	2nd	Combination of energy and capacity from wind and gas-fired generation resources from the market under long-term Power Purchase Agreements (PPAs)
150 MW PPA from existing ERCOT combined cycle	$1,060	3rd	Single energy sourced from a gas-fired generation resource under long-term PPA
350 MW BPUB combined cycle	$1,082	4th	Size reflects economies of scale for capital and operating costs but requires merchant sales of excess energy into the market

B&V 2017 IRP Presentation Slide 10

The 2017 IRP's conclusion, according to B&V's presentation was, "The most economic option is for BPUB to participate in ownership of the Tenaska power plant development Project through owning 200 MW of the plant capacity [emphasis added]." B&V recommended that BPUB continue to monitor market conditions and secure RFPs to evaluate other PPA options.

At the July 11, 2017 joint COB meeting, Management's presentation of the IRP to the Commission showed the same ranking of power supply options as the Board's presentation reflected in Table 5, i.e. indicating Tenaska was ranked the #1 expansion plan to move forward with despite the projected capacity shortage being much smaller than predicted in the 2011 IRP update and despite the issues to date with subscribing the remaining capacity.

Though the Commission remained skeptical and commissioners were looking for ways to end the agreements, meeting minutes reflect the commissioners were advised that an early exit would cause BPUB to lose approximate $8M in Tenaska reimbursements for development costs.

Given Management's propensity to manipulate the narrative, we compared the 2017 IRP to the presentations made to the Board and the COB and reviewed emails and documents circulated among Management, B&V, DTRG, and Tenaska prior to the presentations. The results of our analysis revealed a similar pattern of Management manipulation as was described in prior sections of this report and are fully described below.

In the 2017 IRP submitted by B&V on or prior to May 1, 2017, B&V did not determine that the Project was the best or the most economic option. To the contrary, the 2017 IRP discussed the unlikelihood of the TBGS ever being built due to market conditions:

> *"For several years, Tenaska has explored developing a new 800 MW 2x1 combined cycle unit in the Brownsville vicinity and this was originally expected to be available during the 2020 timeframe. While Tenaska has more recently indicated that the Project may not occur due to economic conditions in the ERCOT market, this option was evaluated as a sensitivity case in this IRP…"*

More importantly, B&V concluded the following with regard to the best and most economical plan:

> *The best BPUB plan involves Sensitivity 5, which consists of the 84 MW (27.7 MW firm) wind PPA in late 2018, followed by the stair-step purchase from an existing combined cycle in 2020 (100 MW) and 2027 (132 MW of which 32 MW is incremental).*

B&V's recommendation, excerpted below, that BPUB should focus its planning efforts on the two options in Sensitivity 5, reflected Tenaska's stated intent to not move forward with the Project and highlighted the opportunities provided by the recently-increased regional transmission network.

> *Given that: a) Sensitivity 5 is the least-cost option, b)* ***Tenaska has indicated that it will provide pricing from an existing combined cycle instead of building a new 800 MW unit****, and since c) other utilities and IPPs in the region could also propose competitively priced combined cycle capacity to BPUB through the recently-increased regional transmission network, it is appropriate that the two options making up Sensitivity 5—the wind PPA and the purchase from existing combined cycle capacity—should be the focus of BPUB planning efforts in the near-term.*

B&V further concluded that a capacity solicitation RFP would be the most effective means of securing low-cost power supplies especially in light of the addition of multiple 345-kV projects in the Lower Rio Grande Valley (LRGV) that increases import capability into the Brownsville area. Thus, just as B&V emphasized in the 2011 IRP (and was ignored by Management), once again B&V was recommending a power supply RFP.

It is also noteworthy that B&V's analysis concluded that BPUB could continue its current practice of using surplus revenues to reduce the FPEC rate charged to customers to below the actual cost of power.

Notwithstanding Management's manipulation, more fully described below, the Project was ranked fourth in the actual 2017 IRP, as illustrated in Table 6 below.

Table 6

EXPANSION PLAN	CPWC ($ MILLIONS)	% HIGHER THAN BEST PLAN	RANK	COMMENT
Sensitivity 5. Wind PPA (2018) with Stair-Step Purchase from an Existing Combined Cycle	1,031	-	1st	Based on a max. break-even capacity price of $144/kW-year that would make the plan approx. 2% lower than the Base Case
Sensitivity 4. Stair-Step Purchase from an Existing Combined Cycle	1,032	-	2nd	Based on a max. break-even capacity price of $130/kW-year that would make the plan approx. 2% lower than the Base Case
Base Case. BPUB Self-build Case Involving a 285 MW, 1x1 7FA Combined Cycle	1,052	2.0%	3rd	Candidate units include natural gas fired simple and combined cycle options from 9 MW to 285 MW
Sensitivity 3. 200 MW Purchase from Possible 800 MW Tenaska Unit	1,096	6.3%	4th	Considered less likely to be built based on current market conditions. An option involving an existing combined cycle as in Sensitivity 4 and 5 is more likely

In addition to the change in the Project's ranking, we also noted other issues with the items in the CPWC Ranking table (Table 5) used in B&V's presentation:

- The CPWC of the Project (ranked 4th in the actual IRP results above) was reduced from $1,096 to $1,004 in the presentation, ensuring its ranking as #1.
- The CPWC of Sensitivity 5 (ranked 1st above) was increased from $1,031 to $1,059 in the presentation, thus ensuring it would be ranked lower than the Project.
- The 350 MW combined cycle, ranked 4th in Table 5, was not listed in the 2017 IRP ranking table above, nor was the 3rd ranked option of 150 MW PPA.
- Instead of the TBGS being "Considered less likely to be built based on current market conditions," as commented above, the presentation described the Project as "Development by Tenaska subject to favorable market conditions. BPUB will participate in ownership with Tenaska." Clearly, the latter comment was intended to obfuscate the true status of the Project.

As discussed in more detail in the Conflicts of Interest Section of our report[67], this change in ranking was a direct result of Management's collusion with Tenaska, with the cooperation of B&V, to manipulate the outcome of the upcoming meeting with the Board and the Commission in what appears to be an attempt to mislead both governing bodies in order to keep the Project from being terminated.

During our interview with Mr. Bruciak, we showed him the rankings in both the May 1, 2017 IRP and the May 8, 2017 presentation along with the fact that at this point BPUB had already known that the Project was not going to happen.[68] He would only respond that both the presentation and the report were done by B&V and that he had no involvement in putting together that report.

[67] Section 6.3.
[68] Per the April 2017 email cited in this report where BPUB noted that Tenaska did not intend to build a smaller plant of any size and did not feel that they owed BPUB any reimbursements.

> *"Like I said, I didn't have anything to do with presenting those reports or putting that in there. That would be a question for Black and Veatch on where did [they] get that? …those aren't PUB documents created internally."*

When we relayed to Mr. Bruciak that we observed numerous instances of BPUB's direct influence and control on presentations and studies over the years, Mr. Bruciak acknowledged that they do but still denied any involvement in the conclusion change, stating that he "doesn't do anything with presentations." Nevertheless, emails and their corresponding attachments tell a different story. While Mr. Bruciak may not actually edit presentations himself, it is evident that he and the rest of the Management team were directly involved in dictating or manipulating the outcome.

We believe that model changes that directly impacted the ranking (i.e. "Please re-rank the sensitivities of CPWC based on lower estimate of gas prices and off system sales", among others), were solicited from Tenaska by BPUB, and forwarded to B&V to either provide responses or apply to the model. Ultimately, it was BPUB's influence and manipulation that presented the Project as the most economical decision.

Furthermore, while B&V may not have directed the changes, their participation is without question, especially given that the IRP PowerPoint, which was incorporated on their B&V PowerPoint template, was presented by B&V employee Craig Brown. However, it is notable that the actual Final 2017 IRP Report does not reflect the changes directed by Management, only the presentations.

Given the above, it is our opinion that the Presentation to the Joint Meeting of the Board and Commission held on July 11, 2017, reflected the product of intentional misrepresentations carried out with collusion between Management, Tenaska, and B&V.

6.2.2.2. Omissions and Misrepresentations

6.2.2.2.1. Management Omitted Knowledge of Consultant Warnings

One of the key advisors of the Project provided a helpful analogy to understand how the Project was supposed to work. He compared the Project to a new retail shopping center. BPUB would be the major department store anchor tenant, which gets the Project started. The rest of the shopping center needs to be filled with smaller stores. If no other tenants can be found the shopping center could not survive. When Tenaska was unable to find the additional subscribers, or tenants from our analogy, the Project ultimately failed.

BPUB did not begin the process of terminating the Project until December 2017, when the Board voted to cancel the indefinite extension agreement, thereby reactivating the critical milestone dates. However, Tenaska's troubles finding additional subscribers began very early in the Project. As early as April 2013, when BPUB had only expended approximately $1.8M on the Project, the subscription deadline was extended for a second time. Notably, when the Project was proposed to the Board in December 2011, Tenaska gave the expectation that the plant would be fully subscribed before the end of 2012.

Permitting issues in July 2013 delayed the plant nine months and the subscription deadline was extended to November 15, 2013, which provided Tenaska ample time to secure the remaining subscribers. To contrast this, the timeframe from BPUB first signing an NDA to discuss the Project and signing the Definitive Agreements was fifteen months. By the end of the nine-month extension to take care of permitting issues it would have been almost one year since the Definitive Agreements were signed by BPUB and Tenaska still did not have a single MOU in place with a potential subscriber. By December 9, 2013, BPUB had expended $8 million in development costs and the November 15, 2013 subscription deadline had passed.

When Max Yzaguirre reported, in July 2014, to the Board that Tenaska expected to have a MOU with a subscriber within one month, BPUB had expended close to $16M. The aforementioned MOU never materialized. Based on conversations with previous Board members and BPUB staff, there was optimism fueled by Max Yzaguirre and Mayor Martinez that the Project would carry forward. Others have described the mood as *overly* optimistic or not objective. By the time BPUB made the decision to begin the process of exiting the agreement in December 2017 nearly $30M had been spent on the overall Project and Tenaska had not found a single additional subscriber for the Project.

BPUB knew in February 2015 that the most promising prospective subscriber put any plans of subscribing on hold. The presentation that Tenaska made before the Board in March 2015, however, still touted them as a possibility citing to Management that the prospect would need additional generation capacity in 2021. This presentation[69] was also the first time that we have found Tenaska on record stating that the ERCOT market needs to improve in order to subscribe the plant as planned and blamed shortsightedness on the part of utility providers who were choosing to purchase power on the spot market in lieu of long term agreements.

It is understandable that after an initial delay in the subscriber obligation, BPUB would agree to extend the deadline. However, after multiple delays, BPUB continued to extend deadlines seemingly without regard to the rising development costs. This is despite a much earlier warning by B&V in 2012 highlighting the risk related to lack of off-takers[70].

> *The development of the Base Project hinges on Tenaska contracting with off takers for a significant portion of the Base Project's capacity. To date, BPUB appears to be the most serious off taker. The identification of other off takers is something that is out of BPUB's control, yet it will determine the size, configuration, and schedule for the Base Project and* ***will likely determine if the Base Project ultimately moves forward. [emphasis added]***

Even without this warning BPUB was, or should have been, aware of the gravity of it being the only off-taker for the Project.

While Mr. Bruciak stated that the Board was kept aware of the progress of marketing efforts and the impacts to the Project timeline, meeting minutes and other documents reflect otherwise. When the inability to find additional off-takers is considered with context that an early assessment noted that it would impact the ability of the Project to move forward, the true status was known long before the original COD came and went. Because this warning and the other potential negative comments expressed by B&V in 2012 purposefully omitted from Board presentations, Management and The Yzaguirre Group were able to easily placate the Board and ask for patience when they should have been weighing the cost of termination over investing in a Project that would never come.

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[69] The version given to Management. An abbreviated version was presented before the Board.
[70] In 2012, B&V completed a technical assessment of the proposed Project where in its conclusion B&V highlighted the most significant Project concerns; one of which was off-takers.

6.2.2.2.2. April Joint Session

During the April 24, 2017 joint meeting there was reportedly a significant amount of tension surrounding the Tenaska Project. Commission candidates and COB residents, who had been publicly demanding answers about the Project spending and rate hikes, arrived at the meeting wearing "anti-Tenaska" t-shirts. During the closed session, the commissioners requested an update on the Project and were informed by John Bruciak that the Project was on hold due to ERCOT market conditions and that Tenaska was actively marketing the Project in Mexico.

Several commissioners expressed concerns about Management's report that nearly $27 million had been spent developing a Project with nothing to show for it. The Board chair at the time recalled that Commissioner Longoria stated, "I want out"[71] during the discussion. In response, Mr. Davidson advised what options BPUB had under the contract.

Mr. Bruciak, advised the Commission that the 2017 IRP had just been completed and would be presented to the Board in May 2017. The IRP would look at the projected load growth and changes in the market and identify options going forward. BPUB agreed to present the IRP results to the Commission in a subsequent joint meeting. As previously stated, the 2017 IRP presentations ranked the Project as the most economic expansion plan option.

What wasn't communicated to the Board and Commission was an April 16, 2017 an email exchange between Mr. Bruciak and Mr. Davidson, where the following was stated:

> *"John, in meeting with Tenaska recently* ***they have determined that the Tenaska plant given market conditions is not the most economic decision for BPUB*** *[emphasis added], their modeling indicates a PPA from existing gas plants and wind are the best option going forward , they have proposed a PPA from one of their plants to consider…"*
>
> *"…Tenaska has no intentions of building a smaller plant of any size in Brownsville , given what we know , when you return lets discuss a strategy going forward to recover our costs invested to date on the Project , Greg Kelly made it clear that he feels Tenaska owes BPUB nothing…On our last face to face with Tenaska* ***a couple weeks ago the Mayor made it clear to Greg Kelly if your [sic] not going to build we want our money back.***[emphasis added]***"***

More importantly, the same day of the joint meeting, Management received the draft IRP. It specifically noted that Tenaska had already indicated that it was not building an 800MW facility in Brownsville and had proposed a PPA from a smaller existing facility instead.

Given the above, Management and Mayor Martinez knew by early April 2017 that the Project was dead in the water. Yet, they still modified and misrepresented the 2017 IRP, pushed for the Project to continue, and misled the Board and COB on the status of the Project, all done with the knowledge, support, and in some cases participation of Mayor Martinez.

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[71] Commissioner Galonsky recalled this event during the August 11, 2020 Board meeting and reiterated during her interview with CRI.

6.2.2.2.3. Negotiations in Mexico

After years of attempting to subscribe the TBGS, Tenaska determined that the ERCOT market was too "soft" and potential subscribers were taking advantage of favorable pricing in the energy spot market. As a result, Tenaska redirected its marketing efforts Mexico. Tenaska noted in March 27, 2015 presentation provided to Management[72] that energy reform was underway in Mexico but it was taking a while to complete and they were leaving the door open to future opportunities.

In June 2015, Tenaska stepped up its efforts in Mexico. Mr. Bruciak informed the Board that Tenaska was interested in hiring BPUB Power Consultant Max Yzaguirre to assist with negotiations with the Mexican state owned utility, CFE. This request led up to an extension agreement executed June 29, 2015. The two main provisions of which were, an automatic extension of the critical dates and Tenaska's agreement to pay a monthly sum of $35,000 "as additional consideration for BPUB's agreement to the extension of Critical Dates."[73]

Approximately one year later, Tenaska provided Management with a timeline of the Project if Mexico negotiations were successful. The timeline touted a potential financial closing date of June 2018 and COD of February 2021. Tenaska also provided the clarification that this was the "most aspirational" Project schedule. The more realistic schedule was to add an additional six to twelve months. Thus, in June 2016, Mr. Bruciak and Management were aware that the earliest COD was likely spring 2022. No records indicate that this timeline was shared with the Board nor was this information relayed to the COB.

During the previously mentioned April 2017 joint meeting with the Commission, Management updated the COB on the status of the Project. Noting that, although the Project was on hold due to conditions in the ERCOT, "Tenaska is actively trying to market the remainder of the pant…to Mexico." However, on April 17, 2016 Management sent the following email to John Davidson of DTRG:

> *"John, Mike Roth called me today advising me Tenaska will be giving BPUB notice that they are cancelling Max Yzaguirre's contract, he believes they have to give Max 60 days notice, I need to see what notice we need to give Max once we here from Tenaska .,[sic] can you look into this upon your return, thanks John"*

Clearly, Tenaska no longer felt that it needed Mr. Yzaguirre's services with negotiations in Mexico. When taken in consideration that this was a part of the same email discussion where two days prior, on April 16, 2017, Mr. Bruciak informed Mr. Davidson on Tenaska's comments that the Project was no longer the most economic decision for BPUB, it becomes clear that this is a signal that negotiations in Mexico had failed.

BPUB was well aware that Tenaska was no longer "actively trying to market the remainder of the plant 600 MW to Mexico." Once again, Mr. Bruciak, with Mayor Martinez's knowledge, intentionally misrepresented the status of the Project to the Board and Commission, even though their role in the Definitive Agreements was that of an agent of the COB.

6.2.2.3. Contradictory Information Presented

Throughout the majority of the life of the Project, BPUB sidestepped questions about the details of the contract and the status. They would state that the Project was delayed and that it was still viable which

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[72] We noted in section 6.2.2.1.1 that there are two versions of this presentation. One provided to Management and one presented before the Board.

[73] The payments are a direct reimbursement of Mr. Yzaguirre's fees.

allowed for the rate hikes to remain in place and to continue with ROW acquisitions taking place in order to complete the associated Cross-Valley Pipeline. As mentioned in the section above, neither Management nor the independent consultants communicated to the Board that the Project was unlikely to move forward.

6.2.2.3.1. Inability to update COB due to NDA clauses

A chief complaint among Commissioners during the Projects lifetime was BPUB's refusal to provide specific requested information about the status of the Project. They were told that it was confidential, and that it was "above their pay grade." When the Board members asked the mayor, who served as ex-officio member of Board, he would only respond "it's coming" and would blame the economy for the delays.

This led to some distrust between the Commission and BPUB with commissioners wondering if BPUB was hiding information. Commissioners were not given advance copies of studies or reports before the meeting, according to Commissioner Jessica Tetreau. Instead, they would be given short handouts as part of presentations that would be immediately picked up. She said BPUB was adamant that documents could not be left.

In response to COB commissioner Cesar de Leon's request to inspect the definitive documents, DTRG drafted a letter, outlining BPUB's agreement to allowing disclosure of the terms. Specifically:

> *"The Agreement, however, allows BPUB to disclose the terms of the Agreement to BPUB's "Affiliates," which specifically includes the City of Brownsville, Texas, but only after BPUB deems that commercially reasonable efforts are undertaken necessary and appropriate to ensure that any such representatives "hold, in strict confidence from any Person" the Confidential Information. The principal operative provision is provided at the end of this letter. Here, BPUB has determined that it may be commercially reasonable to provide you with the Agreement, if doing so will advance the Agreement or other business related to the transaction as set forth in this letter.*
>
> *In order to provide access to the Agreement, BPUB will require (1) a written request from you for disclosure of the Agreement, and (2) your certification that the disclosure is necessary in the conduct of advancing the Agreement or other BPUB business, specifically, your agreement to keep the Agreement's terms confidential. Your agreement to keep the terms of the Agreement confidential extends as long as the Agreement is in effect. If the Agreement is terminated or abandoned, your agreement continues for two (2) years thereafter. To facilitate your request, we provide a form that you can fill out and return, below. Upon receipt of your request, , BPUB will make the Agreement available for your inspection at BPUB's offices.*
>
> *BPUB has determined that it is commercially reasonable to limit disclosure only to its Affiliates working on BPUB's behalf or* ***who have a need to know the terms to conduct business on supporting the Project****[emphasis added]."*

BPUB acted as an agent of the COB when signing the Definitive Agreements. We reiterate that we believe it was reasonable and prudent to restrict disclosure of Project information early in the Project. The risk of financial penalty for breaches of confidentiality may not have been worth supplying contractual details to the COB when the Project was active and moving forward. Once the Project began to deteriorate, and COB constituents were being negatively impacted by a rate increase the Commission authorized as a direct result of the Project, it is fair to say the Commission had a "need to know."

BPUB and Mayor Martinez were not forthcoming with pertinent details that the Commission should have had when making decisions about the rate increases and the termination of the Agreement.

There is no evidence that the changing COD was communicated to the Board. When questioned on whether she was ever told the COD had slipped to as late as 2021, Commissioner Tetreau stated BPUB would never voluntarily tell them when the COD moved. John Bruciak says that he is sure that the Board was aware of the COD updates. As for the Commission he says there could have been joint meeting where the commission was informed but he didn't recall. None of the meeting minutes provided to CRI reflect that the timeline changes were communicated to the COB.

Tenaska's timeline sent to Mr. Bruciak in August 2016, the same month that BPUB asked financial advisors to contribute defenses to a potential rate rescission, said the earliest, most aspirational date for financial close was June 2018. This was if negotiations with Mexico went well and it was footnoted that realistically the schedule would be another six to twelve months. Disclosing this information to the COB would have contradicted any arguments that the final rate increase needed to stay in place to meet the debt obligations. We believe BPUB weaponized its non-disclosure provisions to keep the COB uninformed to stymie decisions that would have been contrary to Management's interests.

6.2.2.3.2. Reasons to keep rate increase

BPUB once again presented a scenario that did not mesh with reality in July 2017 when the Board discussed a 15% rate reduction and its impacts. An excerpt from the closed meeting minutes states:

> *The impacts to lowering rates 15% assuming it was from bond issuance funds would not allow BPUB to be an owner in the Tenaska Project, due to inadequate debt secure coverage. This would require BPUB to fall into a PPA with Tenaska at a higher costs as per existing contract requirements.*

Notwithstanding the factual inaccuracies of the comment above, Management touted this argument while fully aware the Project was unlikely to move forward. Clearly, Tenaska would be unable to call BPUB on their obligation without subscribers. When we asked Mr. Bruciak about this, he said that he did not think there was anything from Tenaska saying the Project was dead and followed up that it would have been a risk to not have the funds in place.

In August 2016, CFO Leandro Garcia requested assistance preparing a list of concerns that would arise if the COB deferred or permanently rescinded the October 1, 2016 rate increase. Bond Counsel Andrews Kurth and Financial advisors Estrada Hinojosa were asked to opine. Mr. Garcia relayed the following:

> *"The scheduled rate increase for Electric totals 7% of which 4% is to support ongoing growth and O&M and 3% to support Tenaska debt service. Deferring the rate increase at this time may be okay (except growth and O&M part which impacts 2017 budget) so long as the current or future Commission is willing to reinstate it at such time that Tenaska provides a notice to proceed. Rescinding the rate increase on a permanent basis will impact BPUB's ability to demonstrate debt service capacity for new Tenaska debt and may result in rating agency negative outlooks and/or downgrades."*

Noe Hinojosa responded to Mr. Garcia's email, he seemed unaware that there was a Commission discussion on permanently rescinding the rate increase but seemed unbothered by the possibility:

"what's the status of Tenaska? if Tenaska hasn't gotten done or there's no definitive date to commence Project, do you think city is obligated to raise these rates?

…your 2017 budget may be impacted by this action ***but would you not agree that PUBs financial condition is at the best it has been in many years if not ever? [emphasis added]*** *so amending the budget will be an inconvenience but shouldn't stress anything else, right?*

we should talk more among ourselves before we go any further.

James[74], it will be very demoralizing if these rate increases were set in stone in a contract and yet not demand that same thing from Tenaska since we all have worked in good faith to make this happen and City has always kept its side of the bargain .

that's my 2 cents."

Bond Counsel James Hernandez provided context that section 4.10 of the purchase agreement contained language that BPUB was obligated to reasonably demonstrate that it could satisfy its obligations from a combination of escrow funds and lawfully available sources of revenue; and that BPUB may have issues[75] ***if*** the rate rescission impacted BPUB's ability to pay the purchase price "when due". He deferred any opinions on legal enforceability of remedies if BPUB was not able to pay to DTRG. Bond Counsel would determine if there would be funds available.

CRI did note that Mr. Hinojosa is the only consultant found in Board minutes to express concern about the Project's status to the Board.[76] We also found email communication where Mr. Hinojosa rejected Management's opinion that Tenaska related rate increases needed to proceed as scheduled. Even though Mr. Hinojosa's opinions were expressed during Board meetings, we believe that the other consultants' and Management's willingness to carry forward and messages to see things through, outweighed the advice of one financial advisor.

We note here again, that as of 2015, construction was on indefinite hold due to ERCOT market conditions hampering Tenaska's ability to market the remaining plant capacity. It was also known in August that Tenaska's earliest timeline for financial close would be June 2018, which means they had ample time to meet their financial obligations. BPUB benefitted from years of rate increases that were put in place to satisfy a debt service that never happened. As early as 2013 the plant delay was projected by B&V to benefit BPUB.

A September 2013 financial forecast presentation by B&V showed that delayed closing of the bonds and capitalized interest would vastly improve BPUB's debt service coverage ratio ("DSCR"):

[74] James Hernandez was BPUB bond counsel from Andrews Kurth, LLP.
[75] When Mr. Hinojosa questioned whether the issues would be financial or legal, Mr. Hernandez responded that section was a mix of legal and financial.
[76] Mr. Hinojosa says that he was never against the Project but felt that management and the Board were overly optimistic.

Figure 9

September 2013 Forecast	Apr 2013	Oct 2013	Oct 2014	Oct 2015	Oct 2016	Oct 2017	Oct 2018
Base Rate Increase	7.0%	7.0%	7.0%	8.0%	7.0%	0.0%	0.0%
Debt Service Coverage	2.50	2.36	2.56	2.95	3.13	1.50	1.51
December 2012 Forecast	**Apr 2013**	**Oct 2013**	**Oct 2014**	**Oct 2015**	**Oct 2016**	**Oct 2017**	**Oct 2018**
Base Rate Increase	7.0%	7.0%	7.0%	8.0%	7.0%	0.0%	0.0%
Debt Service Coverage	2.01	1.95	1.59	1.70	1.61	1.72	1.65
Delta	**Apr 2013**	**Oct 2013**	**Oct 2014**	**Oct 2015**	**Oct 2016**	**Oct 2017**	**Oct 2018**
Base Rate Increase	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Debt Service Coverage	0.50	0.42	0.97	1.25	1.52	(0.22)	(0.14)

Source: Black and Veatch September 2013 Financial Forecast Presentation

A DSCR of 1.0 would mean that an entity has just enough operating income to meet debt service obligations, less than 1.0 would be insufficient income to pay debts. A DSCR of 1.50 would be very healthy as it means that there is sufficient operating income to pay one and a half times the debt. The projections in the 2012 Forecast assumed the Project would proceed on schedule and BPUB would assume bond debt at financial close of the Project. The 2013 forecast assumed a delay in bond issuance, but still anticipated bond issuance in November 2014. Any further delay would have only served to improve these numbers.

After the email discussion was forwarded to DTRG and discussed in a follow-up call on August 24, 2016, Mr. Bruciak requested an email from John Davidson on the calculated time to give notice and exit the Definitive Agreements. He also asked for DTRG recommendations on how to course correct the situation with Tenaska. DTRG provided a list of options available to BPUB but noted that, at the time, there were no immediate exits from the Definitive Agreements outside of a breach by Tenaska. The options were:[77]

- Deliver notice to Tenaska of termination of automatic extensions on 10/31/2016.
- Terminate automatic extensions. Require extensions on 1/1 of each year beginning 1/1/17 or 1/1/18.
- Pay BPUB its cost of money set aside for the Tenaska Project.
- Reimburse BPUB now for all reasonable and necessary Project expenditures to date.
- Reduce purchase price.
- Allow BPUB to reduce 200 MW commitment proportionately if BPUB elects to install new generation or elects to replace existing generation.
- Release BPUB from the restriction which prohibits doing a substitute similar Project with a third party.

[77] The first two options were available to BPUB at any time. The others were recommendations to negotiate BPUB's position.

- Give BPUB an exit to terminate within 9 months after written notice to Tenaska.

None of the presentations on the rate increases appeared to relay this information to the Commission when BPUB was pressed about the need to continue with the Tenaska related rate increases.

In April 2017, after the Commission again pushed for rate rescission, Mr. Bruciak brought up the impending 2017 IRP to postpone Commission action, suggesting they wait for the results that would be available the following month. The IRP results, as discussed above, were presented on July 11, 2017. After months of discussion and a November 2017 meeting in San Antonio, which Mayor Martinez attended, the Board determined that BPUB needed to terminate the Project.

Even after BPUB acknowledged internally that the Project was dead, they still managed to keep the COB and the public in the dark to serve their own ends. When BPUB, with Mayor Martinez's knowledge, canceled the critical date extensions in Late 2017, it triggered a financial close deadline of February 2019. Tenaska was required to give notice within 75 days of the deadline that they would be ready for financial close. When Tenaska defaulted, BPUB made the decision, at the recommendation of DTRG via a November 2018 email, to "…Just let the sleeping dog lie" and not publicize the information. The reason given was that it could interfere with the ROW acquisitions still taking place. At that time, there were still holdouts that were going through the condemnation process and Mr. Davidson wrote:

> *If the holdouts learn that the principal reason for the pipeline no longer exists, they could delay final acquisition by refusing to settle or contesting the acquisition on the grounds that there is no longer a legitimate public purpose for the acquisition Just let the sleeping dog lie.*

Protection of the ROW was cited as a reason to hold on to the remaining Definitive Agreement[78] tying BPUB to the Project. BPUB had the option to terminate this final agreement on August 4, 2019.[79] However, under the advice of BPUB counsel DTRG, BPUB waited until February 4, 2020, nearly the last possible day, to terminate the agreement. The reason was, once again, to avoid any conflicts with the ROW acquisition. Presumably, the termination of the final Definitive Agreement created a need to announce, finally, that the Project was officially over.

6.2.3. Conclusion

Not long after the Definitive Agreements were signed, there were numerous early warnings that it would not proceed as planned. Tenaska's inability to subscribe the remaining capacity was an early warning sign that BPUB should have heeded before agreeing to multiple extensions in the face of mounting development costs. Management was well aware of the risks to the Project if Tenaska had trouble finding off-takers for the excess capacity because a previous B&V report highlighted it, but did not choose to share this information with the Board.

Management selectively omitted key information from the March 27, 2015 where Tenaska emphasized its inability to move the Project forward. Instead Management contributed to an edited version that watered

[78] The Energy Manufacturing Agreement.
[79] Either party had the right to terminate the agreement 180 days after the financial closing date February 5, 2019.

down the negative information or omitted it entirely. During the same meeting, the Board was presented an unachievable COD that both Management and Tenaska knew was far-fetched.

In a November 17, 2015 presentation, this time with the Commission present, Management presented outdated information where it emphasized an exaggerated capacity shortage using outdated data and projections for dates where actual capacity requirements were known and once again, provided a COD timeline that was unachievable.

Management approved edits to the 2017 IRP in order to make the Project seem to be the most economic path going forward. This was done with the full knowledge from a previous meeting with Tenaska and Mayor Martinez that Tenaska was not going to build the new facility. Management also used the impending IRP results to stall rate rescission and Project termination discussions in the April 2017 joint session with the Commission.

In addition to using the IRP to waylay discussions about terminating the Project, Management advised the Commission that Tenaska was actively marketing the Project in Mexico. Management did this despite the knowledge that Tenaska's efforts in Mexico were unsuccessful, so much in fact that Tenaska dismissed the consultant it hired to help with negotiations in Mexico, the same consultant who was simultaneously under contract with BPUB as its strategic advisor in negotiations with Tenaska.

Management selectively omitted pertinent information, influenced presentations, and outright changed facts to keep the Project in play. All the while holding on to a rate increase and proceeding with ROW acquisitions that were both approved to support the Project.

6.3. CONFLICTS OF INTEREST

6.3.1. Tenaska

Tenaska appeared to have influence over inputs and studies connected to the Project. Their input in the 2017 IRP influenced the outcome of final recommendations, moving the Project from a lower placement to the top economical choice presented to the Board.

Tenaska also worked with BPUB as Tenaska Power Services providing providing Qualified Scheduling Entity and Energy Marketing Services. It worked on energy portfolio management, market analysis, congestion revenue rights recommendations, load forecasting, and resource scheduling, risk reporting, optimization strategies and market settlement. Tenaska contracted with BPUB to provide contract support services to PUB with regard to purchases of renewable energy from the Sendero Wind Farm.

Management reached out to Tenaska directly when they considered building new generation. The close relationship that BPUB has built with Tenaska Power Services had a direct influence in BPUB negotiating a project with Tenaska.

6.3.2. Max Yzaguirre

BPUB appeared to have a regular roster of firms that they like to hire as consultants. For example, when seeking out firms to complete the 2011 IRP update, Management compiled a shortlist of three engineering firms that they worked with in the past; clarifying that while there are other firms nation-wide, the three selected understood the BPUB system and provided excellent work in the past. While we have some concerns about how this approach affects independence[80], those familiar with the RFP process, both in BPUB and the COB, have all noted that there are firms with whom they are more comfortable. Mr. Bruciak also noted that there are sometimes specific people that they are comfortable working with and sometimes those people move to other firms.

To the best of Mr. Bruciak's knowledge, the Yzaguirre Group was unknown to Management before the Project began and had never done work for them in the past. Ms. Galonsky stated that Mr. Yzaguirre was known to some members of the community and has family ties to the Brownsville area. Our research found that Mr. Yzaguirre's father previously served on the Board and had deep ties to the community.[81]

We discussed the RFP process with Mr. Bruciak where he explained that Management generally reviews the proposals, shortlists the firms, and makes recommendations to the Board. The shortlisted firms then present to the Board before a vote is taken. It is Mr. Bruciak's recollection that one of more Board members requested that the the Yzaguirre Group be added to the shortlist of potential firms. While Mr. Bruciak could not recall which members requested it, we have determined through discussion with BPUB staff that it would have been Emmanuel Vasquez and Arturo Farias. Black and Veatch was the recommended firm for power supply consultant but, according to Mr. Bruciak, the Board apparently felt the Project was large enough to have two power consultants. The Board unanimously voted to negotiate a contract with the Yzaguirre Group as an additional consultant in the power field.

Mr. Yzaguirre's contract differed from all the other consultants that we've reviewed in connection with this Project. Other consultant contract fees were based on hourly rates with a maximum contract amount and required that a time sheet be included with invoices. Mr. Yzaguirre's contract was a set of three work orders that paid a total sum of $35,000[82] monthly (plus any travel expenses). The contract also stated that he was not required to maintain a record of his time.

In reviewing the three work orders the lack of detail stands out, especially compared to the scope of services attached to the Black and Veatch professional services contract. For example, Work Order Number One is summarized as follows:

- Provide strategic level advice and guidance with respect to the multiple facets of such electric power plant proposal and the related investment and participation decisions that client is considering
- Act as lead negotiator for items that are identified as important by client's Board of directors
- Act as an intermediary between client's Board of directors and B&V/DTRG, assisting in the coordination of B&V's and DTRG's activities
- Acting as an independent set of "eyes and ears" for client's Board of directors.

It further states that B&V was responsible for providing detailed information on: benchmarking, evaluation, engineering, procurement and design strategies, negotiation strategies, investment strategies, financing strategies, strategies for the management of long positions and related issues. Considering that B&V would have been responsible for the bulk of the detailed work, one would question why BPUB needed a second power consultant to organize and interpret their findings.

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[80] We have noted elsewhere in the report that BPUB's comfort with other firms and their reluctance to issue public RFP's can sometimes create an overly comfortable relationship at the sacrifice of independence.
[81] Mario Yzaguirre was a founder of Brownsville National Bank and operated a pharmacy in the city for 32 years.
[82] The original contract signed in August 2012 was $10,000 but an additional work order was added to total $35k

Of note is the final item in each of the three work orders, "Acting as an independent set of 'eyes and ears' for the client's Board of Directors." Setting aside the lack of specificity in that statement, one would assume that it was Mr. Yzaguirre's duty to provide independent advice with regard to all aspects of the Project. This would include advising the Board on the viability of the Project as well as the suitability of extending multiple deadlines to accommodate Tenaska as it struggled to secure subscribers.

Multiple sources have stated that Mr. Yzaguirre was an "optimistic" salesman and kept the proverbial ball rolling by repeated platitudes such as "we're almost there" or "we are near the finish line." When we asked Mr. Bruciak about this, he said he believed Mr. Yzaguirre was reporting what he was hearing from Tenaska. This is contrary to his role as being an independent source of information and relegated his role to simply an agent of Tenaska.

Further, when the Project was stalled and Tenaska began seeking subscribers in Mexico they expressed an interest to the Board in hiring Mr. Yzaguirre to assist with their efforts in Mexico. Instead of terminating the agreement with The Yzaguirre Group, BPUB and Tenaska tied the agreement[83] granting automatic critical dates extensions with monthly $35,000 payments to BPUB. The executed agreement made no mention that the payments were reimbursement for Mr. Yzaguirre's fees, only that the payments were consideration for BPUB's agreement to the extension.

Once this happened, BPUB no longer had a strategic advisor that was operating as the BPUB's "independent set of eyes and ears." Instead, BPUB was holding a Tenaska employee on its payroll, one who did not have an obligation to enlighten BPUB staff on the likelihood that the Mexico market was not a viable option. Despite all this, we note that Mr. Yzaguirre continued to provide updates to the Board that the Project was still being marketed. This is a clear conflict as he could not have informed the Board if he believed that the efforts in Mexico were going poorly while also furthering his other employer's aims to ensure that the Project was held together.

In an email communication on April 17, 2017[84], Mr. Bruciak informed attorney John Davidson that Tenaska called to advise BPUB that they going to give Max Yzaguirre notice[85] that they were terminating their agreement for his services and would need to do the same. If Mr. Yzaguirre was assisting Tenaska with negotiations in Mexico, this could only mean that they determined their efforts in Mexico were unsuccessful. Mr. Yzaguirre of course could not relay this information to the Board as he is obligated to both BPUB and Tenaska for the remaining 60 days of his contractual agreements.

Mr. Yzaguirre played a key role in negotiating all extensions furthering the Project. Every extension that BPUB executed benefitted Mr. Yzaguirre. This is a clear conflict of interest since he continued to be paid a monthly fee, regardless of how much, or little, he contributed to the Project.

6.3.3. Black & Veatch

As noted above, Management has been using B&V and DTRG for approximately 20+ years, in some cases, without contracts or defined amendments to contracts. Thus, the relationship has become quite cozy.

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[83] June 29, 2015 Letter Agreement Extension.

[84] Of note is that this email is a continuation of the previously mentioned April 16, 2017 email conversation mentioned in section 6.2.2.2.2 where Management acknowledged that Tenaska had no plans to build the Project nor reimburse BPUB expenses.

[85] The provision in the June 2015 extension agreement was that Tenaska needed to give BPUB 60 days notice to terminate their monthly $35,000 payments.

1. B&V's level of collaboration with Management appears to be in conflict with their duty to be independent, objective consultants. We consistently noted a significant level of Management input in various B&V deliverables.

   - <u>2011 IRP</u>

     Emails indicate B&V and Management were exchanging whole sections as they were drafted, as illustrated in the excerpts of emails from B&V to Management below:

     12/5/2011: "Attached are drafts of several sections of the IRP. Note that we will send out the remaining sections (Executive Summary, Economic Modeling of Expansion Plan Scenarios, and Conclusions) as they are completed. Please review the attached drafts and provide comments using track changes - as you review, please focus on the content of the sections and do not worry about formatting, table/figure numbering, etc…"

     12/15/2011: Attached is the current draft of the IRP. The sections I have previously sent (Sections 2 through 7) are incorporated into this draft (Marilyn, I made the change to Table 7-5 you provided yesterday). Sections 1, 8, and 9 of the attached draft have not been sent for review prior to now

     12/21/2011: "Our Project schedule assumes that no major rework of the report will be required as BPUB has been reviewing report sections as the Project has been progressing."

   - 2017 IRP

     Emails indicate B&V and Management were exchanging drafts and comments as early as March 7, 2017. On several occasions, B&V's drafts would be followed by 15 or more pages of comments by Management. While consultants often send clients drafts prior to release to ensure fact-based items are correct, the input and control Management was allowed to have over the conclusions and opinions of B&V's work product were inappropriate, as reflected in the comparison of the B&V July 11, 2017 Board Presentation versus the actual IRP described in Section 6.2.2.1.3 above.

     Moreover, Tenaska was provided copies of each IRP Draft and produced their own comments as illustrated in the May 1, 2017 email from Mr. Bruciak to Tenaska (Greg Kelly) seeking input on the April 24th draft of the 2017 IRP:

     "Greg, have not received your comments to our IRP, I'm preparing for next Monday's Board Meeting and running out of time to finalize IRP, John."

     Tenaska sent back a redlined document to BPUB with comments and questions for B&V to both help B&V prepare for the Board meeting and to suggest changes that would put Tenaska back as the best expansion option by running new scenarios on reducing natural gas prices and off-system sales, and alternatively running scenarios without including market sales and purchases option to see if Tenaska option would be more economical.

     B&V responded the following day, defending their ranking of Tenaska but defers to BPUB regarding any re-runs of the model or changes in the sensitivities. As reflected in the final version of the July 11, 2017 presentation, BPUB told them to proceed with the changes that would put the Tenaska option back on top. Interestingly enough, while B&V did update the models, revise the presentations, and present the adjusted information it knew was not accurate as directed by Management, B&V left the actual work product, the 2017 IRP, intact. Thus, if any of the Board or the COB Commission had looked at the actual IRP they would have been aware that the presentation was a misrepresentation of the IRP.

2. In early to mid-2012, B&V's scope was modified to extend it to performing a technical assessment of the Tenaska proposal (Section 6.1.2.3.2 above). Prior to its completion of the assessment whose results could likely promote or kill the Project, B&V was one of three firms asked by BPUB to propose on a power consultant contract to assist with the Project, a contract that would not be needed unless the Project moved forward. Thus, B&V's role allowed for a self-serving determination and created a potential conflict of interest.

3. In August 2012, the aforementioned contract was executed and, according to Management, was comprised of the following:

   - Baseline Deal Parameters: High level Tenaska corporate, financial, and portfolio profile, risk assessment, benchmarking, go/no-go recommendations

   - Review Resource Options: Parameters for 100, 150, 200 MW ownership shares, assessment of PPA, self-build, and RFP options, High level summary of economic limits and risk assessment on options

   - Evaluate reasonableness of potential decisions: Project economic model considering power, grey water, and gas pipeline sizing options, summary of key assumptions, economic model assessing total Project costs, parameters for pipeline size and capacity, economic model for grey water

   - Negotiate Definitive Agreements: Joint Ownership Agreement, Cooling Water Agreement, Wastewater Disposal (if needed), Natural Gas Pipeline/Transportation, Transmission Interconnection(if needed), Land Sal/Lease(if needed), Local Vendor Participation MOU (if needed)

   - Evaluate cost and conditions participation levels: Updated participation economics, fuel/market forecast, deal/contract risks and mitigation plan

One of the tasks identified in the scope of work was for B&V to present the pros & cons of the Project and recommend a Go/No Go opinion on the Project. Proceeding with the Project led to four additional amendments to B&V's contract including the scope items below, and led to other contracts relating to load forecasts, rate studies, and other tangentially related contracts.

- Additional technical and engineering consulting work to extend prior Phase II services by evaluating megawatt ownership options, capacity resource options, and potential risks associated with each, continue to support negotiations with Tenaska by proving input on participation agreement, tolling agreement, O & M agreement, energy management and fuel management agreements, and water supply agreements.

Notwithstanding the above scope items, which clearly included B&V negotiating with Tenaska on BPUB's behalf, B&V was named in the Asset Purchase Agreement[86] (finalized in Jan 2013) as the independent engineer by Tenaska, a position that was not changeable by BPUB.

> "Independent Engineer" means a qualified independent engineer selected by the Seller and approved by the lenders providing the Seller Financing prior to Initial Closing. If Purchaser does not approve of Seller's selection, Purchaser may elect in its sole discretion to engage another qualified independent engineer (subject to Seller's approval not to be unreasonably withheld) and such Person shall be the Independent Engineer for purposes of this Agreement; provided, however, that the following shall be deemed to be approved independent engineers, and if initially selected by Seller, Purchaser will not have the right to engage another independent engineer: Black and Veatch or Burns and McDonnell. In the event Purchaser selects a second independent engineer in the manner described above, (i) Seller, Purchaser and independent engineer shall enter into a separate agreement for the provision of such engineering services, (ii) Purchaser shall be responsible for all costs and expenses for such services and (iii) the Seller and Purchaser shall mutually agree upon a plan to facilitate the collaboration of the two engineers.

This represents a significant conflict as now all three entities (BPUB, B&V, Tenaska) have a shared goal and incentives to keep the Project going as long as possible, potentially to the detriment of BPUB.

4. B&V had a separate contract with Tenaska Brownsville Partners, LLC[87] to participate in plant construction[88] and another contract with Tenaska for another plant.

Given the above, it is our opinion that B&V's level of conflict of interest is significant and divergent. Subsequent to producing the IRP that promoted the Project, B&V was put in the position to evaluate the deal that it's IRP promoted, recommend Go/No Go on the Project it already evaluated, then provide Technical and Engineering consulting in negotiations with an entity that it also had contractual relationships with, all the while being influenced by Management to promote the Project and profiting each step of the way.

6.4. DISPOSITION OF FUNDS

CRI was asked to review the disposition of funds expensed in connection with the Project and the Pipeline. After a review of invoices with their associated support and pay vouchers, meeting minutes, and communications with BPUB staff CRI found no evidence of fraud associated with payments to vendors. Samples of vendor invoices found that payments were approved and paid according the BPUB purchasing department policies.

We did note one anomaly with the support documents attached to some of B&V's invoice. B&V was required to keep a record of time sheets, but they were not included with some of the payment vouchers provided to CRI. We asked BPUB about these documents and Marilyn Gilbert attested that the time sheets were received but due to a data breach at BPUB, they could no longer be accessed.

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[86] One of the Project's eleven Definitive Agreements.
[87] The entity that would construct and run the TBGS once it was operational.
[88] The Engineering, Procurement, and Construction Agreement for the Brownsville Project was executed on July 29, 2014 between Tenaska Brownsville Partners, LLC and Brownsville Power Constructors, a joint venture with PCL Industrial Construction Co.

In total our review of Project related expenditures totaled approximately $30.9 Million was disbursed in relation to the Tenaska project. BPUB wrote off approximately $9.3 Million in expenses. The vast majority of expenditures and write-offs were for Engineering and Legal Fees.

The top 10 percent of payments are highlighted in Table 7 below.

Table 7

Top Vendor Payments

Vendor	Total
DAVIDSON & TROILO REAM & GARZA	$ 4,656,131.36
WILLBROS ENGINEERS (US) LLC	3,726,281.70
AMBIOTEC GROUP, INC.[1]	3,689,660.79
BLACK & VEATCH CORPORATION	2,161,474.79
TETRA TECH, INC.	2,149,425.68
THE YZAGUIRRE GROUP LLC	1,977,066.76
SMITH MURDAUGH LITTLE &	1,622,144.06
ANDREWS KURTH, LLP	1,580,070.55
AECOM USA, INC.	1,269,698.77
TREVINO & BODDEN	1,268,164.17
ATKINS NORTH AMERICA, INC	1,228,122.05
Total	**$ 25,328,240.68**

[1] Two Ambiotec affiliates were paid as Ambiotec Group, Inc and Ambiotec Civil Engineering. The total fees are combined in this Table

BPUB was reimbursed approximately $805,000 for expenses paid to The Yzaguirre Group, LLC.

6.5. OTHER FINDINGS

6.5.1. Pressure and Incentives to Keep Rate Hikes in Place

BPUB was very protective of the Tenaska rate increases. Beginning in 2016, when the COB commission began discussing rescinding or pausing the rate hikes, BPUB started crafting defenses to protect the rate increases. These defenses included contractual obligations to Tenaska, the rate stabilization program, and impacts on city transfer. We discuss the contractual obligations to Tenaska in a previous section where we note that it was obvious that Tenaska would be unable to call BPUB on their obligation without subscribers. We discuss the rate stabilization program in the next section of this report. Here we will focus on the impacts on city transfer and COB as a whole.

Since 2006, BPUB had an obligation to transfer to the COB ten percent of the gross revenues on a quarterly basis. The transfer amount is then reduced by the amount owed to BPUB for COB utility services. The gross revenue calculation is adjusted by funding requirements to the Southmost Regional Water Authority and all costs for the purchase of power and fuel. Thus, the city transfer is directly impacted by any rate increases (or decreases), but increased collections due to the cost of fuel and purchased power[89] do not factor into gross revenue.

[89] See section 6.5.2 for a more detailed explanation of fuel and purchased power costs.

Since the initial Tenaska presentation before the Commission, BPUB has highlighted that the COB would benefit from an increase in the city transfer, something Mayor Martinez enthusiastically supported. We asked Commissioner Tetreau if this influenced the vote to approve the rate increases and she believed that it did. In 2017, after all scheduled rate increases were put in place, the BPUB transfer was almost ten percent of the city budget[90]. In voting for the rate increase, the Commission was, in reality, voting to increase the COB's revenues. We cannot separate this incentive to the city from their motivations when they approved the rate hikes, and apparently neither did BPUB. Approving rate increases and receiving the benefits thereof, does present a conflict of interest for the COB.

In 2020, after it was publicly known that the Project was officially terminated, there was a joint meeting between BPUB and COB. Near the end of that meeting Mr. Bruciak, in his closing remarks, highlighted that before rate rescissions were rolled back the COB needed to consider that they were going to be short on energy in 2021 and that it would be premature to reduce rates before a decision would be made on how to meet that need[91]. He then highlighted the impact to the city transfer:

> *"The biggest part too, and it's a major part is the impact to the city on transfer. Huge reduction in money you are going to be getting from the reduction in rates….just be cautious and take a look at that…certainly we can roll those rates back but there's consequences to that.*

While maintaining that the COB has all rights and power to roll the rates back, BPUB applied the pressure to the COB to keep the city transfer revenue in mind.

In addition to the city transfer, we found a letter drafted by DTRG[92] on behalf of BPUB offering incentive to keep the rate hike in place. According to the draft letter, the COB had identified a need for more fire protection in North Brownsville. The Board was offering to contribute up to $7M for the construction of a new fire station, under the guise that increased fire protection would benefit BPUB as well since they had valuable facilities in the area. Of course, in order to provide such a generous offer, BPUB would need to be able to replace the capital improvement funds. Thus, a condition of the offer was that the final state of the rate adjustments would remain in place and that "future reasonable and necessary rate adjustments be implemented by the City."

Commissioner Tetreau does not recall receiving this letter, and subsequent CAFRs do not show a transfer to the city to build a fire station. The fact remains however that BPUB was willing and able to put pressure and incentivize the COB to both implement and keep rate hikes. The COB's reliance on the transfer to balance its budget not only gives BPUB a level of undue influence but also opens the COB to a conflict of interest when making rate decisions.

BPUB benefitted greatly from the increased equity and surplus funds from the rate increases approved by the COB. Half of the rate increases were for O&M that likely wouldn't have been approved without a large capital project. When that rate increase was in jeopardy, BPUB used its surplus capital improvement funds

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[90] Total city revenues in fiscal year 2017 were $105,702,815. Surplus funds from BPUB were 10,748,466.
[91] None of our research indicates that there was a large capacity shortage that necessitated a need to use the rate increase for additional electric generation.
[92] The memo draft date was September 10, 2016.

as a carrot to dangle in front of the COB in the form of offers to fund special projects and used the city transfer as a pressure point to encourage the COB to keep rate increases in place.

6.5.2. Billing Reduction Plan

In early 2015, the Board began to ask about deferring rate increases while there was little movement on the Project. The rate increases that were approved in 2012 were incremental with the final two increases taking effect on October 1, 2015 and 2016. The Board, based on minutes, were appeased and agreed to be more patient with the Project and all communications implied that there were no further calls to halt the increases that year. The Commission, however was increasingly skeptical of the Project and after Tenaska agreed to present to speak to commissioners in executive session, Commissioner Tetreau said they were even less sure the Project would ever be completed.

In February 2016, Commissioner John Villareal sent an email to BPUB requesting any agreements that legally bound the COB to the rate increases. He indicated that he would be bringing the rate increase to the Commission, presumably to rescind the increases or at least halt the final increase. A series of internal discussions took place among Management to counter any such proposals. It appears that one solution was to create a "billing reduction plan" to lower residential electric bills by "stabilizing"[93] the Fuel Purchase and Energy Charge ("FPEC") that is passed through to customers.

The following is an explanation of billing charges compiled by BPUB financial advisors Hinojosa Garza and bond counsel Andrews Kurth:

> *Under the BPUB Rate Ordinance and the Bond Ordinance, rates and charges collected for debt related to the plant acquisition are treated as an "energy charge" component of the utility customer bill. The energy charge component for debt service must be approved by the Commission.*
>
> *For payments under a long term PPA, BPUB has to collect revenues from utility rates differently than for a debt financing. Under the BPUB Rate Ordinance and the Bond Ordinance, power purchase agreements are treated and collected as "Cost Recovery Charges" a component of the "fuel and power charge" in the utility customer bill. These fuel and power charge components of the utility customer bill are "pass through" charges and do not require approval by the Commission.*

To recap, the rate increase that was approved by the Commission in 2012 affected the energy charge. This figure is set and does not vary as energy prices fluctuate. The FPEC charge changes based on the actual cost of purchased fuel or electricity. BPUB and the COB have little to no control over the FPEC.[94] During the April 2016 BPUB closed session meeting, Leandro Garcia presented the "rate reduction" proposal before the Board. The plan was to use the fuel subaccount to lower the average customer bill (1000kwh) to $102.00.

The goal, of course, was to keep the energy charges (i.e. rates), otherwise they would have allowed the COB to rescind the rate without objection. So in order to lower customer bills to the target $102 goal they

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[93] The program artificially lowered the FPEC. It was not a stabilization.

[94] BPUB can negotiate the cost of energy through long-term PPA negotiations, fuel contracts, Capital Projects, etc. but has no control over the energy market.

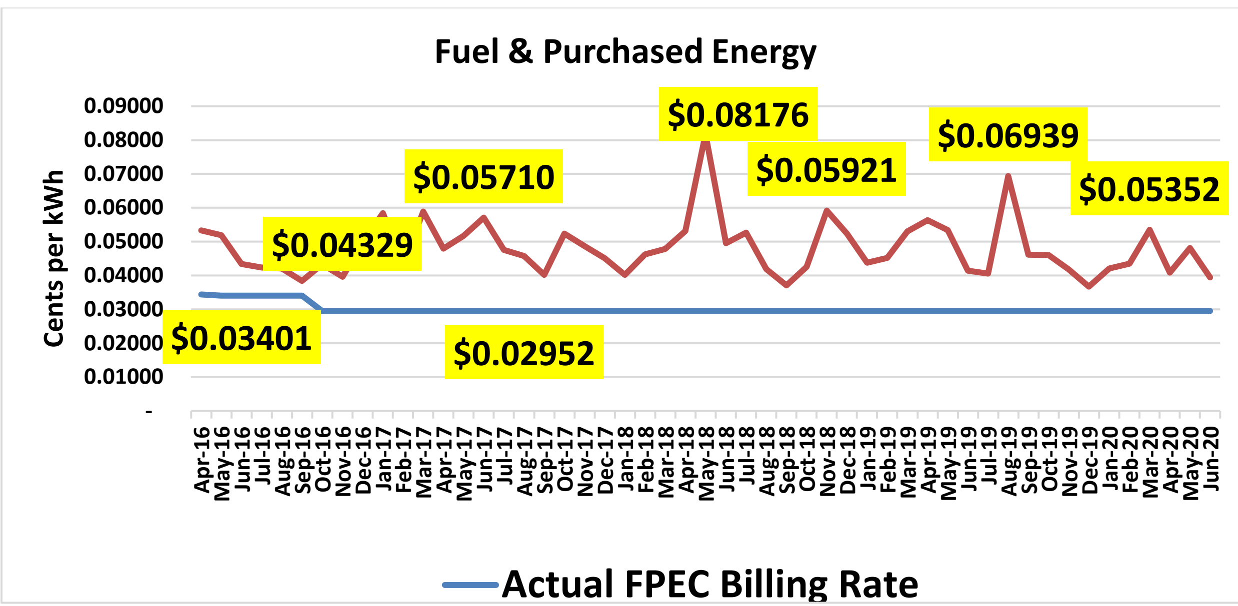
would have to lower the FPEC. COB electric customers were able to benefit from an eight percent reduction in bills and BPUB was able to avoid a loss of revenue from rate rescission.

Over the next several years, this rate stabilization program would be used as a ready defense whenever rate rescission was discussed. More specifically, the argument from former CFO Leandro Garcia would be that rolling back the Tenaska rate increases would cause customer bills to increase, the reason being that actual FPEC was so high that, without the reduction, customer bills would be higher after a fifteen percent reduction in energy charge. According to BPUB, the Tenaska rate increase was actually *saving* customer's money. This point was emphasized by Mr. Bruciak during the August 11, 2020 joint COB meeting.

> "You're going to be giving a false sense of a rate reduction, when you're actually going to have a rate increase. There is nothing we can do with that and it's very clear in the presentation."

In reality, in order to get customer bills down to the $102 figure, FPEC would need to be lowered to $0.029. We reviewed BPUB rate presentations slides and budgets and have not found average Fuel and Purchased Power rates below $0.032[95] in the last 10 years. The following charts were presented to the COB during discussions of the Tenaska Project rate increases:

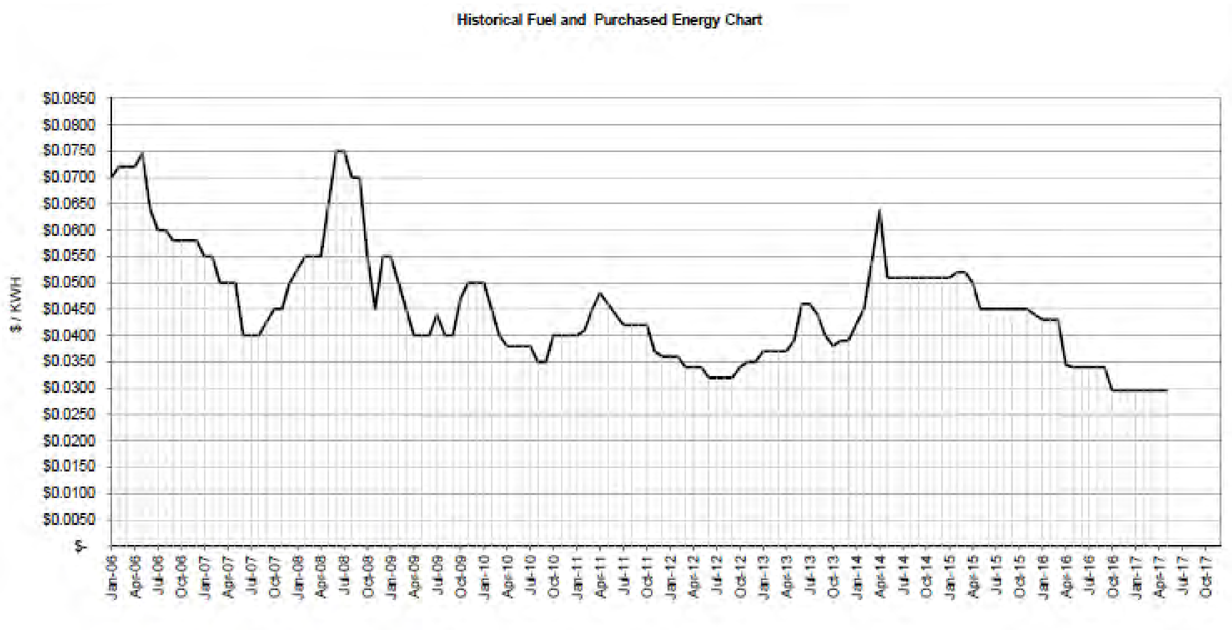
Figure 10



BPUB presentation to COB August 11, 2020

[95] Source: BPUB FY 2019-2020 Budget. Ten Year Rate Analysis: Residential Rates.

Figure 11



BPUB Electric Rates presentation July 17, 2017

As one can see with very few exceptions, rates are rarely below $0.030. Thus, $0.029 is an artificially low FPEC. One would need to look back as far as 2002 to find FPEC rates that low.

BPUB was spending annually more than it was receiving from the rate increases associated with the Project. The annually recurring Tenaska-related rate revenues amounted to approximately $14 million. BPUB has allocated well over that amount annually to fund the fuel subaccount for the stabilization fund. For example, in Fiscal Year 2016, the annual proceeds raised from the Tenaska related increases were estimated to be $14 million. However, BPUB allocated $15 million from the Tenaska revenue to the fuel subaccount for bill reduction, along with an addition $4 million allocated from surplus funds.

By bond ordinance, any surplus in net revenues has to be retained in the Capital Improvement Fund ("CIF"), a restricted cash account. BPUB bond counsel describes a 'closed-loop system' where system revenues must be spent on system related expenses such as capital improvements, system expenses, and to fund the costs of any rate stabilization sub account, or any other similar subaccounts. BPUB legally, with a vote from the Board, could decide at any time to no longer fund the fuel subaccount and discontinue the rate stabilization plan.

In a press release announcing the plan, BPUB wrote:

> "The amount available for bill stabilization does depend on other BPUB obligations, so this reduction shouldn't be considered permanent, but it's something we'll do as long as we're able to support it"[96]

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[96] Clark, Steve. "A Little Relief: BPUB says it has lowered residential electric bills 2.1 percent". Brownsville Herald. June 24, 2016.

Keeping the rate increase intact would have given BPUB flexibility in the use of funds. The rate stabilization fund wasn't codified and BPUB could, at any time, determine that it could no longer fund the program. BPUB's prediction of ending the program should the Commission reduce rates was realized when the COB voted to rescind the Tenaska related increases.

In a press release announcing the decrease in BPUB rates on May 4, 2022, BPUB stated the following:

"Since 2016, BPUB had been using those revenues for its bill reduction program, which kept the fuel, purchased energy and marketing charges (FPEM) on BPUB bills lower than actual costs. The FPEM, seen on a BPUB electric bill as the fuel and energy charge, covers the cost of fuel used for electric generation, purchased power and associated costs. All electric customers pay an FPEM as part of their bill. As the base electric rate is adjusted, BPUB will begin to phase out supplementing the bill reduction program. That means the FPEM will be variable from month to month depending on market conditions during that billing period. Based on current fuel prices, customers will see an increase in their total bill despite the lower base electric rate."

No mention was made of course, that the bill reduction plan was not fully supported by the Tenaska rate revenues alone. Nor did it mention that the fuel subaccount had been funded in the past without the Tenaska increases. In addition to BPUB getting ahead of what will likely be customer confusion over an increased bill *after* a rate reduction, BPUB appears to blame the higher bills on the rate decrease, almost as if it were a retaliation for the decrease itself.

In an effort to hold on to a codified rate increase, BPUB concocted a plan to mask the increased energy charges on customer utility bills. BPUB artificially lowered the FPEC charge to an unrealistic figure then used it as a cudgel to keep the COB from rescinding rate increases.

6.5.3. Delayed Notification to Public in Order to Pursue ROW Acquisition

In 2012 as part of the Project, BPUB proposed before the Commission a plan to build and own a natural gas pipeline. Historically, BPUB relied on contracts with gas providers to supply natural gas to its gas fired generation stations. According to BPUB, the pipeline would not only allow BPUB to more reliably supply gas to its facilities, but would also allow BPUB to become a gas utility provider. The Commission approved the creation of a gas utility in December 2012.

In order to build and own a natural gas pipeline, BPUB would need to begin the ROW acquisition process. Surveying for the Pipeline route began in 2013 as part of the feasibility studies and ROW acquisitions began in 2014. There were concerns from Board members that the ROW acquisitions were premature. In March 2014, Board members Edna Oceguera and Nurith Galonsky expressed concern that hiring Andrews and Kurth law firm to assist with condemnation proceedings was premature. When asked about this during our interview, Ms. Galonsky stated that she didn't think BPUB should be taking on the expense of the ROW while the overall Project kept getting pushed back. She further states that she was surprised when she saw a letter from BPUB with offers for two of her family's properties, though meeting minutes show that BPUB never voted to suspend ROW acquisition.

BPUB's defense of the ROW acquisition process was that there was value in having the ROW in place as it was multipurpose and could be used for other utilities, including the transportation of water. But, BPUB didn't feel that this justification alone was adequate when it came to actual ROW proceedings. As noted previously, BPUB concealed news of the Project's potential failure in order to protect the ROW. BPUB counsel felt that if the intended purpose for the ROW acquisitions, a gas pipeline to serve the Project, no longer existed, the condemnation procedures could be negatively impacted. BPUB even delayed terminating the final agreement in order to prolong the timeline to complete the acquisitions.

We have repeatedly noted that the Project was dead long before BPUB terminated the water agreement in December 2017. BPUB's repeated agreement to extensions that eventually turned into an automatic extension led to additional expenses and prolonged collection of rate increase revenues for a Project that would not go forth. But, BPUB's willingness to delay the demise of the Project was directly beneficial in that it allowed them to continue with ROW acquisitions under the guise of a forthcoming gas pipeline to serve a new generation facility. Mr. Bruciak defended the ROW by stating that there are already potential uses forthcoming, as there are other counties interested in using it for water transport to provide relief from prolonged drought. However, a recently surfaced opportunity does not proxy as justification for decisions made several years prior. By continuing with the ROW acquisitions after April 2017, Management, Mayor Martinez, Eddie Trevino, and others involved knowingly continued the ROW acquisitions under false pretenses.

6.5.4. Inflated Consulting and Attorney Costs Due to Unnecessary Extension of Project

Of all pre-development expenditures, BPUB spent the most on attorney fees. Throughout the life of the Project, including ROW acquisition, BPUB spent approximately $9.2 million on legal services to DTRG, Trevino & Bodden ("Trevino"), Smith Murdaugh Little & Bonham ("SMLB"), and Andrews Kurth[97]. BPUB retained Trevino as local board counsel and DTRG as special board counsel. Andrews Kurth, at the urging of Eddie Trevino, was hired to handle ROW condemnation proceedings and act as bond counsel, while SMLB handled ROW acquisition, condemnation, and eminent domain legal proceedings.

Over half of all legal fees were paid to DTRG at nearly $4.7 million. After reviewing a sample of DTRG invoices, we found that all invoices contained detailed accounting of time and expenses. All sample invoices were related to the Project and billed accordingly.

Trevino was paid approximately $1.92 million over the period April 2013 to June 2018, of which $1.28 million was allegedly for Tenaska related services. However, we could not ascertain why Trevino was involved in the Project to that extent, given that there were six other firms associated with legal fees for the Project and given his role simply as Board counsel. Aside from typically taking five to seven months to produce his billing details, it appeared that most of his invoices revolved around attending meetings, being included in conference calls, and being copied on emails. Moreover, his role as Board counsel was a potential source of conflict due to his elected position of Cameron County Judge. In fact, it appears to be that conflict that sparked his resignation in late 2017.

We identified in in our report section that there were early indication that the Project would not be completed. We cannot provide an exact date of when the BPUB should have exited the contract because of the changing language and multiple extensions. But, we will base our opinion on original projected financial close, July 2015. In order to proceed with financial close, Tenaska would have been required to have the plant fully subscribed. If not, the right to terminate the APA would have been triggered thus allowing the Project to conclude. Based on the invoices provided, we concluded that DTRG would need to invoice BPUB for work in shutting down the Project but expenses related to continued extension

[97] Approximately $640K of Andrews Kurth transactions were classified as "Financial advisor services" but are included by CRI in Legal Services.

agreements, memo drafts, and participation in meetings related to the various Project related expenses would have been eliminated

We have already discussed the continued payments to The Yzaguirre Group in an earlier section. Here we reiterate that Mr. Yzaguirre's advice to "stay the course" only served to prolong payments of $35K monthly. Had BPUB made the decision to terminate when the Project failed to meet its financial close deadline in 2015, Mr. Yzaguirre's contract could have been terminated two years earlier. Granted, at that point Mr. Yzaguirre could more accurately be described as a Tenaska employee on BPUB's payroll, as his fees were actually being paid by Tenaska but filtered through BPUB.

Most of BPUB's Project related expenses after July 2015 were in connection with the ROW acquisition, which Management has continued to claim as a valuable asset. If the Project was terminated in July 2015, we do not believe the ROW acquisitions would have continued once the Project was officially terminated. However, as noted in the section above, BPUB delayed the notification of Project failure in order to protect the ROW acquisitions under the assumption that without the Project there would be additional objection from land owners.

BPUB could have saved the COB millions of dollars in legal expenses had it been prudent and objective when assessing the viability of the project. However, as this report has demonstrated numerous times, the furtherance of this Project appeared to have been intentional.

6.5.5. Lack of Impartial Guidance

Sources that worked with the board told us that most Board members were unfamiliar with the level of technical information involved in many of the major decisions. When experts and engineers came in to the meetings with long presentations and big numbers it was easy to get overwhelmed. When we asked Nurith Galonsky about this while discussing consultant presentations she directly stated:

"…you're really relying on what they tell you."

Mr. Bruciak told us that sometimes with boards and councils their attention span is limited so it would be hard to hold their attention through a presentation with 30 slides. Therefore, Management would sometimes provide the larger report or backup information in advance of meetings to help prepare for presentations and ask questions. He admitted that most of the Board likely did not read the reports but felt that the ones who did generated enough questions. It is apparent however, that the Board did not always ask the right questions and it may not have been within their abilities to do so.

A number of the Board members throughout the timeline of this Project were well educated, and therefore had the ability to read and understand the various reports presented. However, given the depth of detail of some of the reports CRI reviewed, it would take serious commitment to be able to scrutinize and compare presentations given to the original reports. It would have been Management's duty to point out any flaws, caveats, or warnings to the board especially when there is a need to compare a presentation to something that was said months, if not years, prior.

Due to the nature of public Boards, where members serve limited terms, it is difficult to ascertain how much institutional knowledge is retained when it comes to long-term projects. The only consistency at BPUB throughout the life of the Project was Management. Thus, it was Management's duty to provide the context of previous Board decisions.

To illustrate our point, during our interview with Nurith Galonsky, she indicated that she was not always aware of the details of previous reports or contracts. For example, when discussing Max Yzaguirre, and his contracted role, she replied

> "The Board that originally hired him in 2012 was no longer there in 2015, so our understanding of why he had originally been hired was never communicated to us or we never saw it in writing."

We interpret that to mean that she, and other Board members who were not serving in 2012, were not aware of the specific contract language that outlined Mr. Yzaguirre's role and therefore were incapable of accurately evaluating the services provided. As we noted previously, Mr. Yzaguirre's contractual obligation was to be the "independent eyes and ears for the client's board of directors." Perhaps if the Board were privy to that information it would have second-guessed their willingness to allow him to remain as a strategic advisor[98] while simultaneously working for the party they were in negotiations with.

Management however, was fully aware that:

- The 2012 Technical cycle assessment warned that the inability to find off-takers would derail the Project.
- The Beck forecast contained vintage information and the capacity shortage projections should have been re-evaluated.
- The reserve capacity added to capacity projections was not a legal requirement from ERCOT.

In short, Management neglected their responsibility to make sure the Board was well informed before making key decisions on spending tens of millions of dollars.

7. Conclusion

Perhaps more so than any other factor, the driving force behind the 2011 IRP and the subsequent pursuit of the Tenaska Project was the widely publicized impending capacity shortage described in the IRP and frequently vocalized by BPUB and Mayor Martinez. Yet, the 2011 IRP merely parroted an outdated and overstated forecast at Management's direction. Further, Management directed B&V to add an additional capacity reserve margin of 13.75%, falsely claiming to its Board and the COB that it was an ERCOT requirement.

Using allies at the BEDC, Mayor Martinez, and Management pushed the Tenaska Project on commissioners as if it was an emergency, using the artificial "imminent" capacity shortage together with a narrative of failed business development efforts, which they claimed were linked to lack of generating capacity – an intentional fabrication. Management's overemphasis of an artificial and contrived capacity shortage and lost business prospects were key drivers in the decisions of the Board and COB to approve the Project.

Further, given the interference and manipulation of the narrative, it is our opinion that Management, with the participation of Mayor Martinez, intentionally misrepresented or omitted key information in order to ensure that the Project (and its related rate hikes) would be approved by the Board and the COB.

Management had direct influence on several presentations made before both the Board and the Commission. In many cases Mr. Bruciak, Mayor Martinez, other Management members, and consultants omitted

[98] Mr. Yzaguirre's contract with BPUB was in force during his time working with Tenaska.

pertinent information that would have jeopardized support for the Project. In other cases, they outright changed facts to create a false narrative in an effort to deliberately cloud the Project's status and viability.

Later in the timeline, even after BPUB acknowledged internally that the Project was dead, they still managed to keep the COB and the public in the dark to serve their own needs.

Throughout the life of the Project, we observed that Board and Commission members were often not provided with the full details of studies and presentations. Typically, members were shown an extremely summarized version highlighting the key points that Management thought were important or were aligned with their narrative.

Given that Board members typically did not have electrical generation or business experience, the lack of details or the presence of contradictory information likely went unnoticed by the Board. Compounding the issue was that some of the key consultants that were hired to supply independent and objective third party opinions and to be the "eyes and ears of the board," were instead heavily influenced by Management.

However, given the size of the Project and the number of moving parts, Board members should have been more skeptical and asked more questions, especially as the failure of Tenaska to get subscriptions continued to mount.

Overall, Management had the opportunity from the very beginning to follow the recommendations of its consultants and solicit proposals in order to make the most economical decision relating to BPUB's power supply needs. Instead, Management with the knowledge and, at times the involvement, of Mayor Martinez, appear to have engaged in actions to intentionally misrepresent or falsify key facts for the purpose of ensuring the Tenaska Project was approved and the related rate increases were kept in place.

While we did not find any evidence the Board intentionally misled the COB during key decision-making meetings, the Board was aware of the Project's demise in November 2017 but chose not to notify the Commission and the public until August 2020.

Given the findings above, we recommend that our report be forwarded to the authorities for their review and determination of next steps.

8. Restrictions

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