INTEGRATING RENEWABLE ENERGY BEHIND THE METER IN UPSTREAM OIL AND GAS OPERATIONS - PART I

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Alonzo A. Álvarez Meola, P.E.
Senior Member, IEEE
Chevron Technical Center
1400 Smith St
Houston, TX 77002
USA
alonzo@chevron.com

Zach McKinney, P.E.
Member, IEEE
Chevron Technical Center
1400 Smith St
Houston, TX 77002
USA
zachm@chevron.com

Ricardo Rangel
Member, IEEE
Chevron Technical Center
1400 Smith St
Houston, TX 77002
USA
rrxp@chevron.com

Patrick Collie, P. Eng.
Member, IEEE
Algonquin (Liberty) Power
345 Davis Road
Oakville, ON L6J 2X1
Canada
Patrick.Collie@algonquinpower.com

Abstract – The cost of renewable power has decreased rapidly over the last 15 years, making investment in renewable energy an attractive way for any large power consumer to cost-effectively reduce scope 1 and 2 greenhouse gas emissions. As the oil and gas industry evolves to meet the challenges of the energy transition, including greenhouse gas reduction targets, the application of renewable energy resources behind the meter is a viable strategy to meet these needs. This paper intends to be the first of two discussions centered around the integration of renewable power in upstream oil and gas applications. The authors will discuss the process from feasibility evaluations, including power forecasting and greenhouse gas reduction estimates, to major barriers in selecting locations for development. A key technical challenge considered is integrating inverter-based resources to load serving substations. A case study based on a solar farm in West Texas, which has a relatively low cost of electricity, will be used as a model in this paper. Emphasis will be given to behind-the-meter renewable energy challenges highlighting the different economic incentives as compared to in front of the meter applications.

Index Terms — behind-the-meter, renewable power, GHG reduction, renewable energy, oil and gas, upstream, onshore, solar power, PV, inverter-based resources, ERCOT, LCOE, 4CP

I. INTRODUCTION

This paper touches on a host of topics around the case study of a solar farm being connected to a load serving substation behind the utility meter in West Texas. At the time of this writing, the project is starting detail engineering with construction scheduled to start in the summer of 2022. This paper discusses how the project was developed to this point, with a follow up paper expected on construction, commissioning, and operation of the facility.

A. Levelized Cost of Energy Comparison

According to the U.S. Energy Information Administration (EIA), Levelized Cost Of Electricity (LCOE) refers to the estimates of the revenue required to build and operate a generator over a specified cost recovery period. In other words, LCOE is a useful tool to compare different types of generators on a $/MWh basis. For renewable resources, U.S. federal tax subsidies are sometimes included, and the trend is very clear. For instance, according to Lazard's LCOE analysis [1], the mean unsubsidized LCOE of utility scale Solar Power (PV Crystalline) has come down from around $359/MWh in 2009 to about $36/MWh in 2021; that is a 90% decline. A comparison with other types of generators can be seen in Fig. 1.

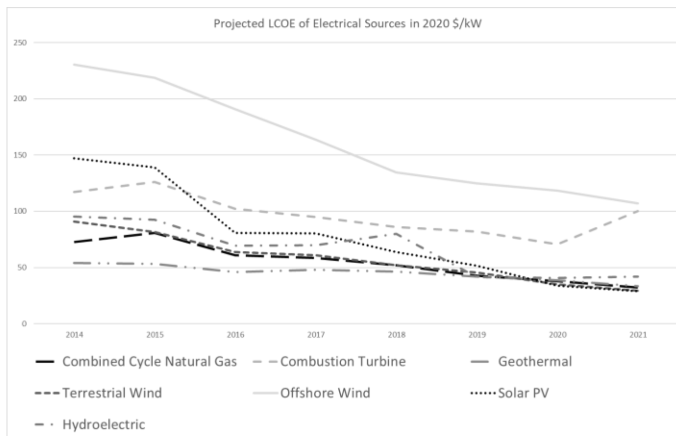

Fig. 1 Historical Unsubsidized LCOE Comparison [2]

The LCOE trends are generally down regardless of generation source, but solar experienced a steep decline from 2009 – 2015. This rate of decline exceeded all other forms of generation, bringing solar into a highly competitive economic position as a source of electrical energy. The decline in cost is largely due to a reduction in the cost of modules, as well as efficiency improvements, and a general reduction of the price of the components of a PV system.

When evaluating the economics of solar for a given location, a comparison must be made between the LCOE and the avoided cost of energy. In the case studied, the avoided costs included the reduction in energy charges, as well as demand charges under the Four Coincident Peak (4CP) construct in ERCOT (Electric Reliability Commission of Texas). 4CP will be explored further in section VII(C), but in essence, this demand charge is based on the average 15-min demand at the time of the monthly ERCOT system 15-min peak demand for the summer months. While solar power is a non-dispatchable resource, meaning an operator is not able to adjust the output of the PV farm based on the load or grid conditions, solar farms provide an environmental and economic benefit for industrial consumers in Texas based on current market conditions. Section VII of this paper discusses the economic evaluation specific to this case study.

B. Behind the Meter vs. in Front of the Meter

The case study used in this paper is based on a solar farm connected "Behind the Meter" (BtM). The traditional design of a solar farm connected directly to the transmission grid will be called "in Front of the Meter" (FtM). Descriptions follow below and are shown graphically on Fig. 2.

In general, most utility scale solar plants are connected in front of the meter, which means that the PV farm inverters are connected to a step-up substation that is exclusively dedicated to export the power. For the power to serve any loads it must access the transmission system and thus cross the utility meter. Any loads present at the substation of a solar farm connected FtM are auxiliary loads. FtM plants may be dedicated to serve loads through the use of Power Purchase Agreements (PPAs).

In contrast, behind the meter means that the substation is set up as a load serving substation. Power from the PV farm feeds loads directly without going through the transmission system and therefore not going "through the meter" to serve internal loads. PV generation in this configuration is relatively novel to Oil and Gas (O&G) load serving substations. A BtM solution can be designed as a non-export or export plant by installing capacity less or greater than the load of the facility served by the substation. Depending on the solar farm design, regulatory constraints, and utility interconnection agreements, a BtM solar farm may produce an excess of energy allowing the facility to net export to the transmission system for periods of time.

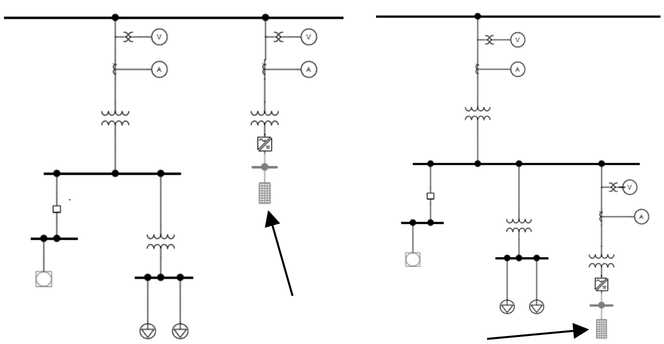

Fig. 2 FtM (Left) and BtM (Right) Generic Configuration, Solar Farm Model is Identified with an Arrow.

The project may need to be assessed by the electrical utility regardless of configuration, FtM or BtM. FtM projects can be expected to build new facilities for the Point Of Interconnect (POI) for the utility, finance any upgrades to transmission facilities required by the new generation, and build an export substation for the solar farm. BtM projects may have to upgrade the existing utility POI and separately build an additional Internal Point Of Interconnect (IPOI) between the solar farm and the load serving substation. The IPOI may be accomplished by modifications in the secondary bus.

Each installation has unique needs and requirements and should be evaluated on a case-by-case basis to determine whether FtM or BtM design is best.

II. BEHIND THE METER CASE STUDY

A. Integration of Behind-the-Meter Power Generation

1) *Power Demand Forecasting*: When deciding where to locate the solar farm, power forecasting is crucial. Existing production forecasts are generally used for the development of power demand forecasts. For optimization of the solar farm size, and to meet the energy needs of the field, to reduce operating expenses, and to generate returns, the size of the PV plant is designed around the forecasted loads of the production field. For further discussion of forecasts see Section IV.

2) *Physical Interconnection*: In this case study, the producing oil field is connected to the electrical grid at an existing substation. The challenge is to find the most efficient and cost-effective way to connect the solar farm. An additional constraint is limiting the length of the collector line to reduce overall capital and operational expenses. The field has a steady historical average demand of approximately 10 MW with expected growth to 18 MW and is supplied by a single outdoor 138:21.6 kV substation with two 24/32/40//44.8 MVA transformers and multiple feeders. The secondary bus of this substation has a tie breaker normally open between bus A and B, and a transfer bus, which allows any feeder to be connected to either transformer. See Fig. 3 for further details.

A critical area of focus is the need for coordination between the project team and operations. After leveraging the correct stakeholders and completing a preliminary design, it was decided to extend the secondary bus to accommodate a new feeder to be dedicated to the solar farm. More details on this topic will be discussed on Section VI(A)(1).

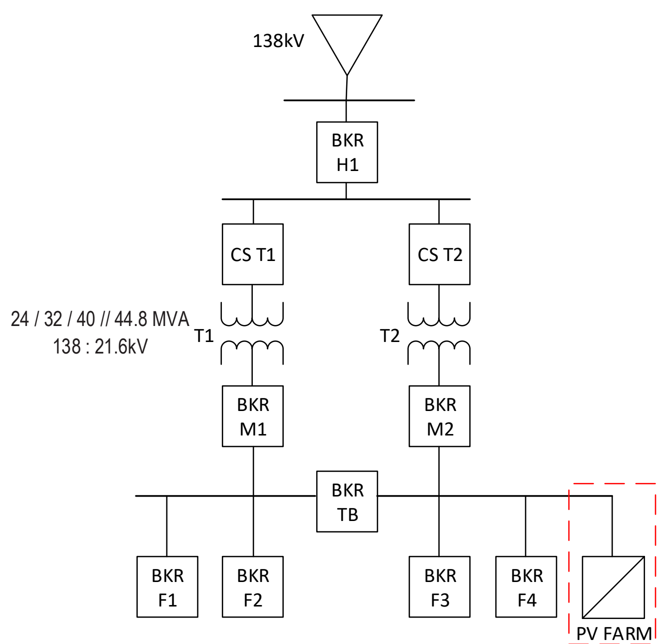

Fig. 3 One-Line Diagram of the Load Serving Substation. Breaker (BKR), Circuit Switcher (CS), Trasnformer (T)

3) *Land and Mineral Ownership:* The fuel for a PV plant is solar radiation; therefore the location of the plant is one of the most important things to consider in solar power development. Terrain has a significant impact on the design of a solar farm. Therefore, topological evaluations, soil and earth composition and other geotechnical evaluations must be conducted. Annual weather patterns, solar irradiance, solar arc in the sky during

seasons, and other meteorological considerations may affect the physical size of the plant.

Upstream O&G companies are well experienced at working with land and landowners as the core business is the extraction of minerals. However, leases that are designed for solar development can be quite different, especially when they involve lands related to exploration and production of oil and natural gas. Texas, like many states and countries, tends to have three parties involved when it comes to land: those with surface rights, those with mineral rights, and mineral lease holders. In many cases, for the extraction and production of hydrocarbons, the operator will deal directly with surface rights and mineral lease holders and not necessarily directly with the mineral owners. Conversely, for solar development, it is imperative to secure approvals from mineral rights and lease holders in order to provide assurance to lenders and financing partners that the project will retain the requisite surface rights for the life of the asset.

B. Solar Plant Development

The schedule and deliverables for a solar facility designed to serve a dedicated load BtM may vary from traditional solar generation plants.

1) *Organization:* There are numerous ways the team can be assembled, and many frameworks for building a business model in which to operate. Whether the project will be stand alone, a part of a larger program, developed internally, developed by third parties, or some hybrid, many types of professional backgrounds will be needed. The project team for this study case was largely business and commercial, but included decision analysts, strategic planning, and engineering support. Because the goals of the project team included positive economic returns and reduced energy costs, the business and commercial insights were invaluable.

2) *Location Selection, Opportunity Assessment:* For servicing O&G exploration and production assets, selecting an oil field that is largely electrified presents an attractive opportunity. A field with large electrical loads in a region with high solar capacity factors further improves the opportunity. As ideal locations are identified, establishing the forecasted facility loads and determining whether electric power export is allowable will allow the team to further identify and frame the opportunity. This case study made a good candidate for development because the oil field is expected to have 18 MW average demand of relatively steady industrial electric loads with high capacity factors and it is fed by a single substation with available land nearby.

3) *Feasibility Studies:* Studies were conducted to optimize the land location for the solar facilities, validate assumptions, and identify any possible fatal flaws. With a large area selected for the study, maps were developed with industry standard setbacks and constraints overlayed. These maps were particularly useful for communication with members outside the team, and with the Transmission Service Provider (TSP) for the generation interconnection agreement. Environmental constraints and regulations were identified, and a roadmap was created. Geological surveys, environmental, archeological, and visual impact studies were conducted. The team also developed capacity and energy yield estimates which helped validate the land requirements assumptions.

Alternative strategies for the IPOI were identified and assessed. The transmission system capacities and potential bottlenecks were identified along with the interconnection processes. Economic evaluations for wind and solar facilities connected in front or behind the meter were completed. These topics will be further developed in Section III.

4) *Resource Selection / Optimization:* Due to the falling cost of PV Panels [4], short procurement lead times on panels and supporting structures, and competitive overall economics, a solar farm was determined to be the best fit for this case study. Similarly, due to falling prices for photovoltaic material, bifacial panels, which can produce energy more efficiently were selected. Unlimited single axis trackers were chosen, similarly because of the falling cost of implementation and the improved energy yield. As demand charges are significant in the cost of electricity, the size of the solar farm was optimized for the maximum benefit in terms of reduced energy expense, reduced 4CP charges, and additional revenue from wholesale energy sales.

5) *Development Plan and Final Investment Decision (FID):* A development plan that included economics, scope, preliminary cost and schedule, financing, funding, preliminary engineering, procurement, construction, commissioning, and turnover to operations was built and presented to management for FID approval. Subsequently, requests for proposals were issued and reviewed, and contracts for the engineering and construction of the solar farm were issued.

At the time of this writing, the case study project has been granted FID and detailed design and engineering are in progress. The following sections will be further developed in Part II of this paper: Detailed Design, Engineering, Procurement, Construction, Commissioning Energization and Commercial Operation Date

III. FEASIBILITY STUDIES

A. Conceptual Design

During early concept scoping and engineering, a conceptual design is developed considering the general size, shape, location, configuration, and other key parameters of the solar farm. This conceptual design may move or evolve significantly as the project is further developed. A model of the PV plant was developed using specialized software that calculated total expected annual energy yield based on hourly weather patterns at the approximate latitude and longitude where the farm is to be built. The make and model of the inverters, expected PV technology, and basic tracker design are incorporated to improve the accuracy of the model. Bi-facial solar panels and single axis trackers have become abundant and cost effective; therefore, these parameters were assumed. Once the capacity factor is determined and annual yield expectations are met in the model, the amount of land needed can be determined and the layout of the arrays can be established. Current photovoltaic technology requires between two and five acres per DC MW generated. The DC side of the plant will be oversized to improve AC output at dusk and dawn as well as to compensate for age-related panel degradation later in the life of the plant.

1) Equipment Constraints: As the solar farm will be constructed and interconnected to an existing facility, the nameplate output of the PV plant cannot exceed the equipment ratings or capacity of the substation. Careful consideration and attention must be given to the ratings of the bus work, circuit breakers, transformers, and other equipment. Should the desired generating capacity exceed equipment ratings, additional engineering, construction, and equipment may be needed. For example, if the expected current output of the solar farm is greater

than the rating of the substation breakers, a dual feed through two breakers or some other redesign may be required. For a BtM plant, extensive substation modification may be necessary for the IPOI, extending a bus, adding bays and new breakers, and so forth.

2) *Power Requirements:* The plant size at this stage in the process is estimated solely on the power requirements and demand profiles available to the engineering team. In the experience of the authors, it is better to perform the feasibility studies on the largest estimated size if not completely defined. The work performed during the feasibility stage will be helpful when submitting the interconnection applications, which in most cases will also allow the applicant to reduce the size of the application without the need for a complete re-study.

B. Technology Selection

In the development framework of the case study, the team determined that solar was the preferred technology. However, the development of wind power was evaluated during the feasibility studies, for which a full desktop study was completed.

The studies for the wind alternative included full resource and energy estimates, an indicative wind rose (which shows average wind speed and direction) at the project location, estimation of number of Wind Turbine Generators (WTGs), layout of the WTGs, noise and shadow flicker studies, and an estimated cost and schedule. For the solar alternative, the team carried out a solar resource assessment, making some industry standard assumptions, such as the type of PV modules, inverters, trackers, and soiling loss.

Additionally, environmental and permitting considerations were compared between wind and solar, as well as interconnection processes, schedules, capital, and operating costs. The single most important driver for this case study in the decision of developing PV was the overall schedule including equipment lead times and additional resource studies. For wind, collecting at least one years' worth of data at hub-height is crucial for having a quality development plan, and to secure funding. For this project, although the expected returns were comparable between the two options, total turn-around time was the deciding factor between wind and solar (1 year of difference).

C. Site Selection

Although the team in the case study had selected general areas for the development, the feasibility studies were particularly useful to narrow down the exact location of the PV farm. The single most important technical factor for the team was the proximity of the farm to the substation. In other words, limiting the length of the collector line was a key consideration. The second most important factor was land and mineral ownership.

From the point of view of an O&G operator, working with the land department in tandem with the feasibility team was key. As mentioned in Section II(A)(3), the mineral rights, lease, and surface ownership all play a role in selecting the most optimal land.

IV. FIELD POWER DEMAND FORECASTING

A. Typical O&G Upstream Onshore Loads

Most Integrated Oil Companies (IOCs) have their own way of planning for electrical infrastructure for onshore fields. In the case of this paper, the operator does careful annual 5-year forecasts estimating load growth based on three factors:

1) *Artificial Lifting Method:* This includes the different production methods used to produce oil, such as: Electrical Submersible Pumps (ESPs), gas lifting using gas engine drives or electric motors, and rod pumps. Power consumption can vary dramatically for each production method. Gas compressed for the export pipelines was also included in this category since it is linked to gas lift.

2) *Surface Facilities:* The primary electrical loads for this category include those needed to separate oil, water, and gas, plus the load of transferring and injecting water. The largest power consumption is typically water injection facilities (with the exception of gas compression which was covered under artificial lift).

3) *New Technologies:* Consideration is given to all new technologies that will be implemented at a particular area, such as electrified oil rigs, electric driven hydraulic fracturing systems, switching from gas engine drives to electrical motors for gas lift, etc.

B. Forecast Calculation

A procedure was developed to produce an accurate power forecast. First, the team analyzed the historical Primary Metering Equipment (PME) data to find the historical 15-min peak demand and average power demand, shown in Fig. 4.

15-min peak demand is often used since it offers the optimal power consumption profile to size the power system. However, some consumers prefer to use 30 minutes or 60 minutes peak demand, which would further smooth out the curve. Fig. 5 shows a 60-min peak demand for a typical IOC onshore field. It is important to note that peak values have short durations.

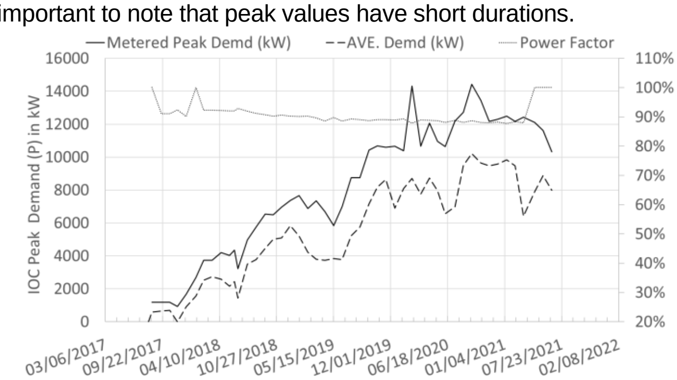

Fig. 4 Historical Peak and Average Demand

The second step in the procedure is to calculate the historical load factor and demand factor, shown in left half of Fig. 6. Using the PME data, the load factor is the quotient of average power and peak demand. The demand factor is the peak demand divided by the total installed nameplate power of all equipment. The demand factor for each area in a field (oil, water, and gas) is then calculated.

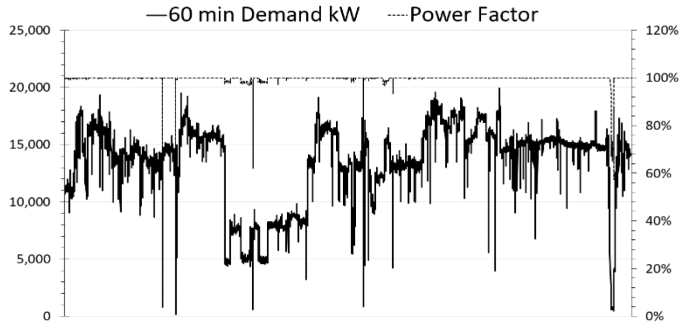

Fig. 5 Representative year 60-min Peak Demand

Next, the individual power coefficients for oil, water, and gas are calculated. These coefficients take into account the standard motor nameplate data, maximum pump flowrate, and demand factor, as shown in the right half of Fig. 6.

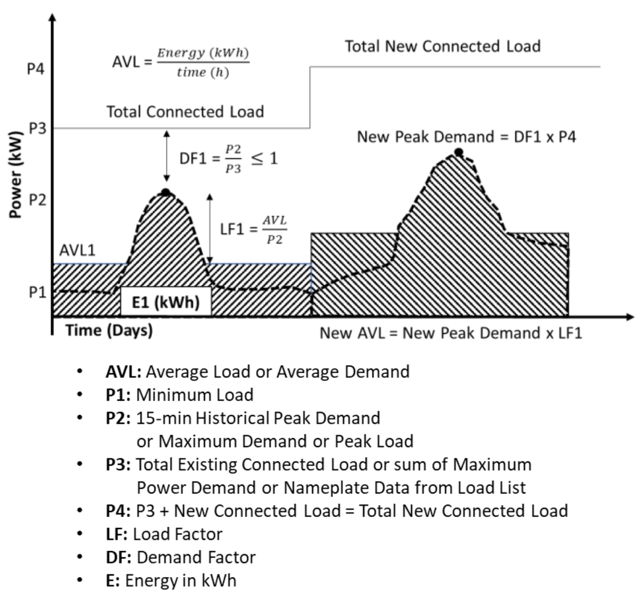

Fig. 6 Demand and Load Factor Calculations

To calculate the peak demand forecast, the power coefficients mentioned above are multiplied by the forecasted production numbers. Equation (1) shows this calculation.

$$P_{peak} = \sum[\Theta Q_{oil} + \mho Q_{water} + \Upsilon Q_{gas}] \quad (1)$$

Where:

Q – Forecasted flowrate
Θ – power coefficient for oil facilities
$\mho$ – power coefficient for water facilities
Υ – power coefficient for gas facilities

Finally, the load factor obtained previously is multiplied by the peak demand numbers to obtain the average demand. The average demand is the most desirable number to use for sizing the PV farm due to its correlation with historical data. Fig. 4 shows the difference between average and peak. Fig. 7 shows a completed power forecast incorporating the PV farm.

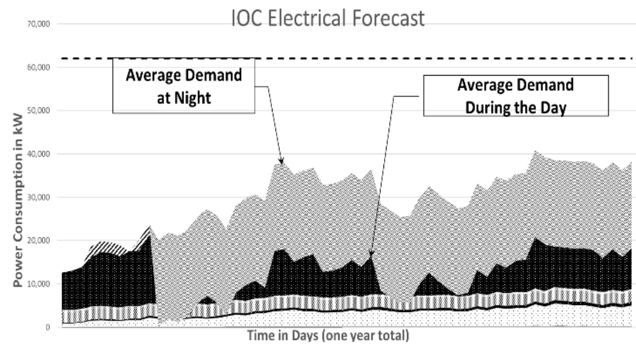

Fig. 7 Power Forecast Using Average Load Forecast

V. GENERATION INTERCONNECTION APPLICATIONS

For the purposes of this paper, the authors focused on the application process in ERCOT. However, every system operator has a similar goal; to make sure the generation addition can be accepted by the system without detriment. Additionally, each ISO or jurisdiction has their own specific requirements. The utility will want to understand, in detail, the type of generation, size, capability, capacity factors, inverter technology deployed, system performance and tuning. The installed solar farm will be required to perform in concert with the existing transmission system and connected generators

In ERCOT, if the interconnecting entity (IE) is applying to interconnect a generator above 10 MW, they must follow the ERCOT Planning Guide Section 5: Generation Resource Interconnection or Change Request [3]. There is a lengthy application that must be filled out with details of the substation, equipment, and plant, after which the applicant must pay for the system operator to perform a series of studies (voltage ride through, steady state, short circuit, stability, and a facilities study), which are called the Full Impact Study (FIS). The guide mentioned above describes the interconnection process and is summarized in Table A-1 in Appendix A. After the studies are complete, the applicant is notified if there are any upgrades needed for the integration of the plant. These are typically paid by the applicant, or in some jurisdictions could be absorbed by ratepayers.

The interconnection process in ERCOT from submission of the application to signed SGIA can take a year or more (see table in Appendix A). Although signing the interconnection application is a big milestone, the interconnection process does not end until energization and Commercial Operation Date (COD) are achieved.

VI. GENERAL CONSIDERATIONS FOR BTM

A. PV Plant Design

The basic component of a PV plant is the solar panel (also known as a module, or PV module). Each solar panel is an array of individual cells of PV material arranged in a series-parallel circuit to achieve a desired voltage and current output. These cells and wiring are encased by glass and encapsulant material and mounted in an aluminum frame. The panels are connected in series, called strings, to build to the rated input voltage for the inverters and several strings are connected in parallel to achieve the design power input rating of the inverter. Several inverters are then connected in parallel. These inverter groups are relatively modular in nature; thus, a solar farm can be built up in increments equal to an inverter skid size.

Based on the inverter technology selected, the strings of modules that are wired to the inverters are collected in DC collector lines and cabinets. The arrays are sized such that the range of input voltages, due to daily and seasonal variation, falls within the design minimum and maximum voltage of the inverter. In planning for optimal power output and design life of the plant, as PV panels degrade, the DC wattage sizing of the plant may be greater than the inverter. An overbuild of 20% – 40% of the DC plant is common.

inverters are mounted together on a skid, connected in parallel to a skid transformer that steps up the output of the inverters from low to medium voltage. The medium-voltage output of several skids is then connected to a medium-voltage collector system in a designed topology, such as single-ended, double-ended, or ring-bus, and further collected into the solar farm substation. There, the interconnection to the BtM substation may be made or another step-up transformer may be used to connect the solar farm to a transmission system.

1) Substation Modifications: As mentioned in Section II, in a typical O&G field, the most economical and convenient place to tie in the farm is the load serving substation that supplies the field. However, the authors know that not all upstream onshore fields have substations. In many cases primary or secondary metering equipment type arrangements with the utility are set, which would make the tie-in point more difficult to identify and select. In such cases, the PV farm could be placed closer to heavy loads, such as compressor stations.

In the case study, a substation was available for the project to tie in, and made the integration of the farm possible. The substation was outdoor 138:21.6 kV with two 24/32/40//44.8 MVA transformers and multiple feeders. The fact that this substation was in West Texas in land owned by the operator, made it possible for the fence to be expanded as needed to make room for the extension of the bus. As of the date of the writing of this paper, detail engineering is not complete, but the scope of work has been identified in two major scopes: primary (138kV) and secondary (21.6kV). For the primary, the main modifications were due to the utility requiring the addition of a three-breaker ring bus switching station owned and operated by the TSP directly upstream of the existing substation, as shown in Fig. 8.

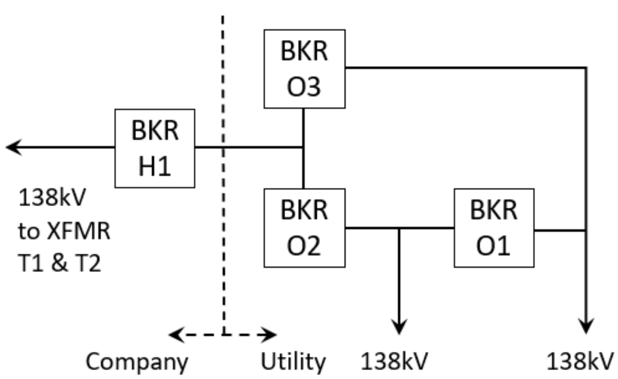

Fig. 8 Three Breaker Ring Bus

For the secondary, an expansion of the bus on the west end of the substation is planned to add one new feeder bay, breaker, and trench/conduit. Additionally, installing a new rack in the control building for relay/controls is also in scope.

As the substation was originally designed as a load-serving substation, the 138:21.6 kV transformers were specified as Delta primary and Grounded Y secondary. This configuration in generation service may result in an overvoltage scenario during a single line-to-ground fault on the high side of the transformer or at any point on the 138 kV bus. The coefficient of grounding was evaluated in the primary and secondary of the transformer in order to determine if the system would incur any overvoltage for any grounding faults. The conclusion of this analysis found the coefficient of grounding less than 80%. More detail on how this scenario is addressed will be presented in the follow-on paper.

2) Power Factor: For this case study, the power factor in the substation to be modified is relatively high for an oil field (>0.90), and the PV farm will be designed to maintain or improve the power factor. A common issue outside utility-scale solar power is the worsening of the power factor at the point of interconnection when the inverters only generate real power. However, in the case of this farm (and any other utility-scale farms) the quantity and configuration of inverters will be specified to supply or absorb reactive power to 0.95 pf leading and lagging, as measured at the POI. This is the typical requirement for transmission-connected generators and is particularly useful in a field which could use pf correction.

An interesting feature of the inverters that were selected in this case study is their ability to generate reactive power at night, which can further help with the overall power factor at the point of interconnection.

One curious issue the authors ran into on a separate project, which was BtM, but non-export is that the TSP wanted the farm to operate the inverters in Automatic Voltage Regulator (AVR) mode. This topic will be discussed further in Part II of this series.

3) Equipment Selection At FID, major assumptions were made in terms of the solar panels, inverters, transformers, and other components of the PV farm. Those assumptions will be solidified during detailed engineering.

The reason for making equipment specifications early primarily lies in the interconnection process with the ISO. The interconnection applications for most utilities requires a preliminary design, so that the impact studies can be completed (FIS in ERCOT). Key to the studies modeled in the interconnection studies are the inverters. Inverter models developed by the manufacturer had to be tuned to behave according to expectations. While these design details may evolve according to the needs of the project and requirements of the interconnection agreement, they will be a given basis of design for the remainder of the project.

VII. VALUE CREATION

A. Partnership Structure

For the case study in this paper, the commercial framework is built on a special purpose vehicle (Seller) that is a partnership formed between the solar developer and an affiliate of the Buyer, established for the purpose of building and operating the solar facility. In this arrangement, the existing production field is the off-taker of the majority of the power and will sign a Power Purchase Agreement (PPA) with the Seller.

B. Economic Case

As in any solar development anchored with a PPA buyer, there are two economic points of view, the seller and the buyer. Based on the combined revenues of the PPA and wholesale market energy sales, the seller will see a return consistent with ranges of return in the industry and a positive NPV. From the second perspective, the Business Unit (BU) acting as the PPA buyer contributes no upfront capital towards the solar facility, and will see savings in the form of reduced electricity costs over the term of the PPA.

Although the Seller will supply power to the BU via the PPA, the BU will continue to purchase power from the utility at certain times of the day. The energy supplied by the solar facility replaces energy (MWh) that would have been purchased from the utility during the day. Combined with the reduction of 4CP demand charges, this results in an overall reduction of electricity costs for the BU.

C. Four Coincident Peaks (4CP) in ERCOT

4CP charges are calculated based on the average of the customer's integrated 15-min demand at the time of the monthly ERCOT system 15-min peak demand for the months of June, July, August, and September of the previous calendar year [7]. 4CP is used in a demand calculation that appears on utility invoices in ERCOT under Transmission Distribution Service Provider (TDSP) charges which include a Transmission Cost Recovery Factor (TCRF). The TCRF portion of the bill is determined by multiplying the 4CP rate by the 4CP demand. This tariff is then applied evenly over the twelve months of the following year. Therefore, if the demand during these four critical periods is reduced in the current year, a portion of the bills for the following year will be reduced.

Historically, the 4CP intervals occur on the hottest day of the given summer month, and typically in the late afternoon or early evening as shown in Table A-2 in Appendix A. Dates are not shown, but each timestamp represents a specific 15-min interval on a particular day in the given month and year.

Solar production peaks do not perfectly align with the typical 4CP interval of 4-6pm (16-18h). However, given the project location relative to its time zone and single-axis tracker technology, the PV plant is still expected to generate electricity within this window. This production, when BtM, will directly reduce the demand, and by consequence the 4CP charges. Furthermore, by oversizing the PV plant relative to the load, shown in Fig. 9, the reduction of demand can be further expanded by increasing production during the expected 4CP hours. The optimization of this 4CP charge reduction was key for the sizing and economics of the project.

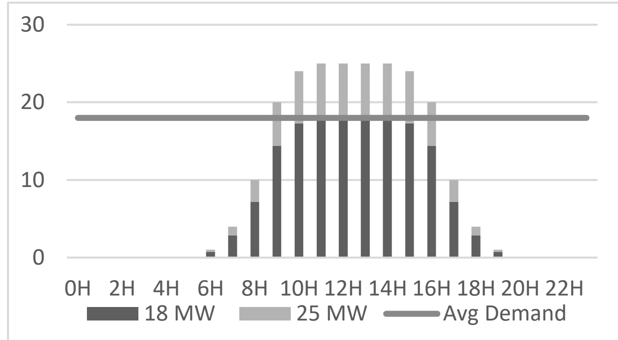

Fig. 9 Example Daily Solar Production (MW) of PV Plant

D. Optimization

Initial project development work included optimization of the following key economic drivers:

1) *Solar PV Plant Size:* As shown in Fig. 9, increasing the PV plant size provides an increase in the forecasted reduction of 4CP charges. Larger project sizes can also contribute to economies of scale and reduced CAPEX on a per MW basis. However, a larger plant will produce more power beyond that which can be consumed by the BtM load. Excess power must be injected into the transmission system and sold on the wholesale markets. West Texas has seen explosive growth in renewable energy (RE) development in recent years leading to congestion issues (basis and curtailment) for new and existing generators. Depending on local solar and wind conditions, generators in the region can expect lower than average power prices, and in certain cases, be forced to curtail their power generation; BtM generation alleviates these congestion issues. The authors expect that in other markets, optimization would skew towards larger plant sizes with increased wholesale market exposure, even for BtM applications, as long as equipment ratings are respected.

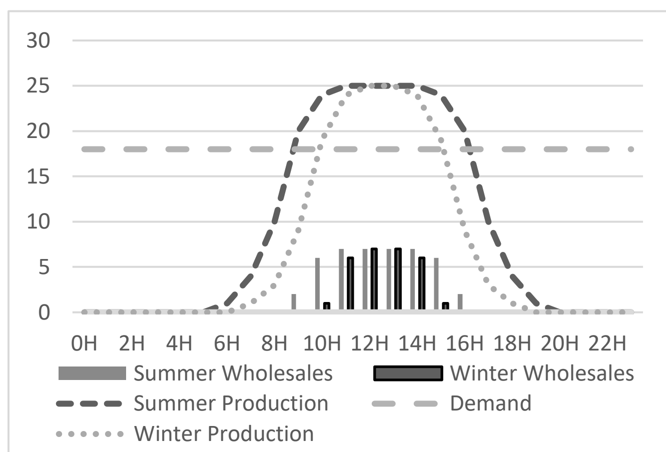

Fig. 10 Typical Sales Volume (MW) – Summer vs Winter

A key feature of this analysis was the BtM configuration of this case. Due to the variable nature of solar power generation, and the fixed nature of the BtM load, the implication of increased sizing on wholesale market exposure is not straightforward. If the solar project's nameplate capacity is sized in excess of the load, the ratio of energy exposed to the wholesale market is not equivalent to the ratios between MW ratings of generator and load.

$$\frac{MW_{Load}}{MW_{PV}} \neq \frac{PV\ energy_{load}}{PV\ energy_{total}} \quad (2)$$

This is due to the fact that in the summer months a higher proportion of intervals will result in excess generation vs. winter or cloudy days. Regardless of seasonality or weather, the early morning and late afternoon hours will always provide less generation than mid day. See Fig. 10 for more detail on this phenomenon for a PV plant sized at 25MW with a BtM load of 18MW. The Ratio MW_{load} : MW_{pv} = 0.72, but the ratio of $PVEnergy_{load}$: $PVEnergy_{total}$ = 0.86 in year 1. See Fig. 11.

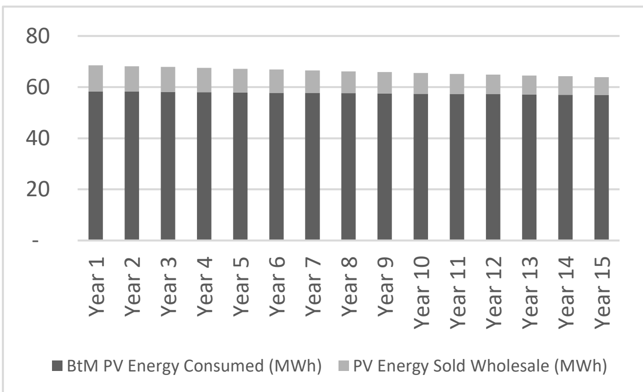

Fig. 11 Energy consumed BtM vs Energy Sold Wholesale

2) Battery Energy Storage

The integration of a Battery Energy Storage System (BESS) was also evaluated. The BESS would have improved the facility's 4CP reduction as well as provide marketable ancillary services to ERCOT. However, due to the BtM configuration, participation in the ancillary services markets was limited to less than 25% of what would have been available to FtM. Without the projected ancillary services revenue, the BESS was no longer advantageous. Oversizing the solar PV plant slightly in excess of the load provided the optimal balance of 4CP reduction and PPA price based on economies of scale and limited wholesale market exposure. The authors expect that as prices for BESS continue to fall, and regulations evolve, BESS integration with solar will provide improved economics and reliability over solar alone. Fig. 12 compares the 4CP reduction of different alternatives.

E. Greenhouse Gas (GHG) Impact

As mentioned in other sections of the paper, the case study consisted of a load serving substation connected to the utility on the primary and oil field loads on the secondary, where the PV farm will be interconnected.

The U.S. EPA (United States Environmental Protection Agency) defines Scope 1 Emissions as direct GHG emissions that occur from sources that are controlled or owned by the same organization that consumed the power (e.g., gas turbine or diesel generator emissions) [5]. Scope 2 emissions, on the other hand are indirect GHG emissions associated with the purchase of such power. Scope 3 emissions are more complex to account for, and are emissions not associated directly or indirectly with the consumption of power, but with the value chain. Following the EPA guidance on the classifications of emissions, the case study in this paper only affects Scope 2 emissions. By integrating renewable power directly with the load of the field, the Scope 2 emissions for operations is reduced by 941 pounds per MWh produced by the solar facility [8].

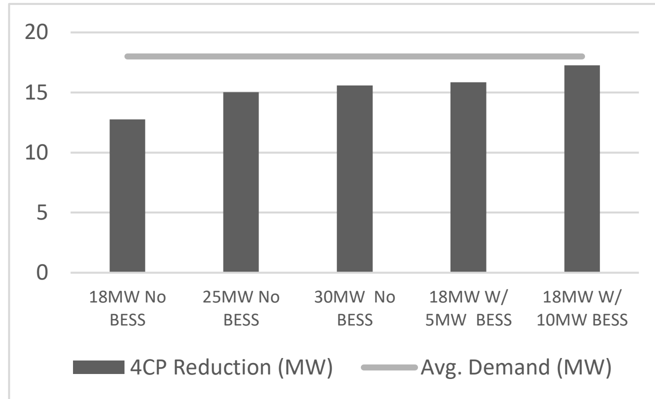

Fig. 12 4CP Reduction Alternatives comparing solar farm size with and without BESS option

VIII. CONCLUSIONS

Development of a renewable energy resource to serve a dedicated load is technically and economically viable. As a matter of fact, in the current business and regulatory landscape, this is a cost effective way to reduce emissions. While integrating a dedicated resource behind the meter has some technical considerations, standard engineering approaches may be used to provide solutions.

Selecting the location for a renewable resource is critical to the success of a project. There must be a large enough load to be served to make a sufficient impact. The presence of a central substation for an oil field adjacent to available land of sufficient size presents an attractive opportunity while the large, steady load of a production oilfield is suitable to capitalize on the opportunity. The natural size of an oilfield works to its advantage in siting a solar farm that can be land intensive at 2-5 acres per MW.

The organization of this project was built around a developer / O&G operator partnership serving an internal business unit of the O&G operator. The Seller will appreciate a reasonable return while the business unit expects to see modest savings in their power bill. Future savings, or savings in other locations, may be found in carbon reduction. While carbon intensity varies by location, in this study, 941 pounds of carbon for each MWh is avoided.

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XI. VITAE

Alonzo A. Alvarez Meola is an Electrical Engineer at Chevron. He graduated from The George Washington University with a B.S. in Electrical Engineering (2011) and an M.S. in Engineering Management (2012). Since joining Chevron in 2013, he has held positions in upstream Facilities Engineering covering automation, power systems, project engineering, and for the last two years he has been involved in renewable power. He is a registered professional engineer in the State of Texas and Connecticut.

Zach McKinney graduated from Angelo State University in 2001. After serving in the United States Navy as an Electricians Mate in the nuclear engineering program, he worked as a shift electrical and control systems specialist in the steel industry. He joined Chevron in 2009 working in field automation, measurement, and electrical power systems. He completed his BSEE at Arizona State University in 2019 and is currently a Senior Electrical Engineer at Chevron. He is a registered Professional Engineer with the State of Texas.

Ricardo Rangel is an Electrical Engineer at Chevron Technical Center in Houston. He graduated from Zulia University, Venezuela with a B.S. in Electrical Engineering (1991) and an Electrical Safety specialist from Los Andes University in 1999. He also has experience in Upstream, Downstream, Petrochemical, and LNG power systems. In 2018 he joined Chevron as Electrical Power System SME.

Patrick Collie has worked within the solar energy industry since 2014 and is currently a Project Manager at Algonquin Power & Utilities Corp. Since joining Algonquin in 2019, he has directly contributed to the development and construction of over 300 MWs of utility-scale solar energy projects in Virgina, Maryland, and Texas. Prior to this, he worked in a variety of Project Management, Engineering, and Construction roles within the Canadian solar industry. Patrick is a licensed Professional Engineer in Ontario, Canada and holds a B.Sc. in Mechanical Engineering from Queen's University.

APPENDIX A

TABLE A-I
ERCOT INTERCONNECTION PROCESS TIMETABLES

Task	Entity	Time (days)
Acknowledgement of GINR Application	ERCOT	1-10
Notification of Additional Information Needed to Complete Application	ERCOT	1-10
Perform Security Screening Study (after application is deemed complete)	ERCOT	10-90
Decision to Pursue FIS (following issuance of Security Screening Study by ERCOT)	IE	<180
Develop Scope Agreement for FIS (following IE's Notification to ERCOT of desire for FIS and remittance of appropriate fees)	IE, ERCOT, and TSP	<60
Perform FIS (following agreement on scope)		40-300
Steady-State and Transfer Analysis	TSP	10-90
System Protection Analysis (following Steady-State Analysis)	TSP	10-30
Dynamic and Transient Stability Analysis (following System Protection Study)	TSP	10-90
Facility Study	TSP	10-90
SSR	TSP	60-180
Study Report Review and Acceptance (following issuance of FIS)	ERCOT, and TSP	10-15
FIS Posted to Market Information System (MIS)	ERCOT	<10
Report stability resolution findings to ERCOT	TSP	<90
Negotiate and Execute Standard Generation Interconnection Agreement (SGIA) (following acceptance of FIS)	IE and TSP	180

TABLE A-2
Historical 4CP intervals (time beginning - CDT)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
June	16:30	17:00	16:30	16:45	17:00	16:45	17:00	17:00	17:45	17:00
July	17:00	17:00	16:45	16:45	16:00	17:00	17:00	16:30	16:45	17:00
Aug	17:00	16:45	17:00	17:00	16:30	17:00	16:45	17:00	16:45	17:00
Sept	17:00	16:45	17:00	17:00	16:15	16:45	16:30	16:45	14:30	17:00