Houston, TX | August 3, 2022

2Q 2022 Earnings Package

PLAINS ALL AMERICAN

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Second-Quarter 2022 Earnings Conference Call

Wednesday, August 3, 2022

Roy Lamoreaux:

Thank you, Sheree. Good afternoon, and welcome to Plains All American's second-quarter 2022 earnings call. Today's slide presentation is posted on the Investor Relations website under the "News & Events" section at plains.com, where an audio replay will also be available following today's call. Important disclosures regarding forward-looking statements and non-GAAP financial measures are provided on slide 2. An overview of today's call is provided on slide 3. A condensed consolidating balance sheet for PAGP and other reference materials are located in the appendix.

Today's call will be hosted by Willie Chiang, Chairman and CEO, and Al Swanson, Executive Vice President and CFO. Other members of our team will be available for Q&A, including: Harry Pefanis, President; Chris Chandler, Executive Vice President and COO; Jeremy Goebel, Executive Vice President and CCO; and Chris Herbold, Senior Vice President, Finance and CAO.

With that, I will now turn the call over to Willie.

Willie Chiang:

Thanks Roy. Good afternoon and thank you for joining us. Today we announced second-quarter results above our expectations, reflecting continued execution of our long-term goals and initiatives as well as strength in both our crude and NGL segments. In summary:

- Second-quarter Adjusted EBITDA attributable to PAA was $615 million
- We increased our full-year 2022 Adjusted EBITDA guidance by $100 million to plus or minus $2.375 billion, which is $175 million above our initial February guidance. This was

driven by outperformance in both our NGL and Crude Oil segments due to higher volumes and higher commodity prices

- As a result, we now expect to achieve the midpoint of our leverage target range of 4.0 times by year-end 2022
- In regard to buybacks, we repurchased approximately $50 million of common units during the quarter, bringing year-to-date repurchases to approximately $75 million, and total repurchases of $300 million since program inception
- Additionally, we are increasing our 2022 asset sales target by $100 million as a result of greater clarity on asset sales anticipated during the balance of the year. Al will provide more detail on our quarterly results and our full-year outlook in his portion of the call

As highlighted on slide 4 and 5, the overall fundamentals of our business remain constructive as North American shale remains key to meeting global energy demand. Current activity levels in the Permian are running roughly 10% ahead of our forecasts, and we expect to see between 650,000 and 700,000 barrels per day of production growth exit-to-exit during 2022. Our operating leverage and integrated business model with large-scale supply aggregation, quality segregation, flow assurance, and access to multiple markets has positioned us well to support increasing producer activity levels. Both our crude and NGL systems have meaningful capacity to grow alongside the needs of our customers for the next number of years, and we are well positioned to capture incremental volumes with minimal capital investment.

At the beginning of July, our Permian Gathering JV closed a bolt-on acquisition for the remaining 50% ownership interest of the Advantage Pipeline for approximately $65 million, or $42 million net to Plains' interest, plus customary closing costs. The negotiated transaction provides the JV additional operational, commercial, and capital synergies at an attractive multiple. The acquisition costs associated with this bolt-on opportunity are more than offset by the incremental proceeds expected from the previously mentioned increase in 2022 asset sales.

In our NGL segment, we continue to advance capital-efficient optimization and debottlenecking opportunities at our existing facilities. Furthermore, we expect growing western Canadian gas production to drive incremental gas border flow volumes towards our strategically located Empress facility.

With regard to our financial strategy, we expect to continue generating significant Free Cash Flow over the next several years, and we intend to allocate this cash in a manner that takes into account the progress we have made to date on our leverage, while increasing cash returned to equity holders through distribution growth and opportunistic buybacks, as well as continuing to make disciplined capital investments. As noted in my opening remarks, we have made significant progress in strengthening our balance sheet. We entered the year with leverage at 4.5 times with the expectation of finishing 2022 at the high-end of our target, or 4.25 times. We now expect to exit the year at the mid-point of our target which is 4.0 times. The improved trajectory allows us to further accelerate our goal of increasing return of capital to our unitholders over the coming years.

Before turning the call over to Al, I would like to mention that we published our 2021 Sustainability report last week. As reflected on slide 25 of the appendix, we have made continuous improvement in our emissions and advanced sustainability in many areas of the company. We are proud of these achievements and look forward to continuing the dialogue with many of you on our Sustainability performance.

With that, I will turn the call over to Al.

Al Swanson:

Thanks, Willie. We reported second-quarter Adjusted EBITDA of $615 million which includes the benefit of higher straddle plant volumes at Empress due to increased gas border flows, elevated commodity prices benefitting our pipeline loss allowance revenues and higher volumes on our Permian Basin long-haul pipelines, primarily flows on Basin Pipeline to Cushing. Slides 16 and 17 in today's appendix contain quarter-over-quarter and year-over-year Segment Adjusted EBITDA walks which provide more detail on our second-quarter performance.

A summary of our 2022 guidance is located on slides 6 through 9. We've increased our full-year 2022 Adjusted EBITDA guidance by $100 million to plus or minus $2.375 billion. Our updated guidance is $175 million above our initial February estimate largely as a result of higher commodity prices and frac spreads benefitting our C3+ spec product sales and volumes in the NGL segment as well as increased prices on pipeline loss allowance barrels and incremental Permian volumes in the Crude Oil segment.

We remain focused on disciplined investments and our outlook is summarized on slide 10. This is consistent with our May guidance, and we do not anticipate any meaningful changes in our capital program for the balance of the year.

I also want to share a few comments on how inflation impacts our business. Generally speaking, our inflation impacts are more moderate than some of the other energy sectors. Our capital program is modest, and we have proactively managed some costs through earlier purchases of materials. As expected, fuel and energy prices are higher as a result of the higher commodity prices, and we are seeing increased pricing on equipment, materials, and services, which we are mitigating through strategic sourcing, utilizing bulk orders, and rebidding. All this being said, we continue to expect annual escalators to offset expenses and provide a modest net benefit.

On capital allocation, our framework remains consistent. We are generating meaningful Free Cash Flow and increasing the allocation to equity holders while reinforcing balance sheet strength and flexibility. Year-to-date, we have repurchased approximately $75 million of common units out of the up to $100 million or so we ear-marked for 2022. Longer-term, we will continue to be opportunistic with repurchases as we monitor our business outlook, leverage, equity valuation and yield as well as disciplined future capital investment opportunities. A summary of our current financial profile is located on slide 11.

With that, I will turn the call back over to Willie.

Willie Chiang:

Thanks, Al. Today's results reflect another solid quarter of performance and execution. Fundamentals remain constructive, and our asset base and business continue to perform well in the higher commodity price environment, capturing incremental growth via the operating leverage within our system.

Looking forward, we continue to build momentum into 2023, and Plains is very well positioned to generate meaningful Free Cash Flow to the benefit of our investors. Over the last few years, we've made solid progress on optimizing our assets, completing our multi-year capital buildout, forming numerous strategic JVs, including the Plains Oryx Permian JV, and continuing to improve our safety, environmental and sustainability performance. Additionally, as we have detailed in our remarks, we have continued to improve our balance sheet and increased capital returned to unitholders. Given the acceleration of our deleveraging and improved financial flexibility, we plan to have discussions regarding our capital allocation framework with our Board of Directors, and I look forward to sharing additional thoughts with you in the coming quarters. In summary, we've accomplished numerous initiatives over the last few years, and we believe our business is very well positioned today and going forward. A summary of our execution and positioning, as well as key takeaways from today's call, are provided on slides 12 and 13. With that, I will turn the call over to Roy to lead us into Q&A.

Roy Lamoreaux:

Thanks, Willie. As we enter the Q&A session, please limit yourself to one question and one follow up question and then return to the queue if you have additional follow-ups. This will allow us to address the top questions from as many participants as practical in our available time this afternoon. Additionally, our IR team plans to be available throughout the week to address additional questions.

Sheree, we are now ready to open the call for questions.

03-Aug-2022

Plains All American Pipeline LP (PAA)

Q2 2022 Earnings Call

CORPORATE PARTICIPANTS

Willie C. W. Chiang
Chairman & Chief Executive Officer

Roy I. Lamoreaux
Vice President-Investor Relations, Communications & Government Relations

MANAGEMENT DISCUSSION SECTION

Operator: Good day, and welcome to the Plains All American's Pipeline Second Quarter Earnings Call. At this time, all participants are in a listen-only mode. After the speakers' presentation, there will be a question-and-answer session. [Operator Instructions] Please be advised that today's conference is being recorded.

I would now like to hand the conference over to your speaker Mr. Roy Lamoreaux. Please go ahead

<<Roy I. Lamoreaux, Vice President-Investor Relations, Communications &

Government Relations>>

Thank you, Sheri. Good afternoon and welcome to Plains All American's second quarter 2022 earnings call. Today's slide presentation is posted on the Investor Relations website under the News & Events section at plains.com, where an audio replay will also be available following today's call.

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With that, I'll now turn the call over to Willie.

Willie C. W. Chiang
Chairman & Chief Executive Officer

Thank you, Roy. Good afternoon, and thank you all for joining us. Today, we announced second quarter results above our expectations, reflecting continued execution of our long-term goals and initiatives as well as strength in both of our crude and NGL segments. In summary, second quarter adjusted EBITDA attributable to PAA was $615 million.

We increased our full year 2022 adjusted EBITDA guidance by $100 million to plus or minus $2.375 billion, which is $175 million above our initial February guidance. This was driven by outperformance in both of our NGL and crude oil segments due to higher volumes and higher commodity prices.

As a result, we now expect to achieve the midpoint of our leverage target range of 4.0 times by year end 2022. In regards to buybacks, we repurchased approximately $50 million of common units during the quarter, bringing our year-to-date repurchases to approximately $75 million and total repurchases of $300 million since the program inception.

Additionally, we're increasing our 2022 asset sales target by $100 million as a result of greater clarity on asset sales that we anticipate to complete during the balance of the year. Al will provide more detail on our quarterly results and our full year outlook in his portion of the call.

As highlighted on slide 4 and 5, the overall fundamentals of our business remain constructive as North American shale remains key in meeting global energy demand. Current activity levels in the Permian are running roughly 10% ahead of our forecast and we expect to see between 650,000 and 700,000 barrels a day of production growth exit to exit during 2022.

Our operating leverage and integrated business model with large-scale supply aggregation, quality segregation, flow assurance and access to multiple markets has positioned us well to support increasing producer activity levels. Both our crude and NGL systems have meaningful capacity to grow alongside of the needs of our customers for the next number of years and we are well-positioned to capture incremental volume -- capture incremental volumes with minimal capital investment.

At the beginning in July, our Permian Gathering JV closed on a bolt-on acquisition for the remaining 50% ownership interest of the Advantage Pipeline for approximately $65 million or $42 million net to Plains interest plus customary closing costs.

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As I noted in my opening remarks, we've made significant progress in strengthening our balance sheet. We entered the year with leverage at 4.5 times and with the expectation of finishing 2022 at the high-end of our target or 4.25 times. We now expect to exit the year at the midpoint of our target, which is 4.0 times.

The improved trajectory allows us to further accelerate our goal of increasing return of capital to our unitholders over the coming years. Before turning the call over to Al, I'd like to mention that we published our 2021 sustainability report last week.

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With that, I'll turn the call over to you, Al.

Alan P. Swanson Chief Financial Officer & Executive Vice President

Thanks, Willie. We reported second quarter adjusted EBITDA of $615 million, which includes the benefit of higher straddle plant volumes at Empress due to increased gas order flows elevated commodity prices benefiting our pipeline loss allowance revenues and higher volumes on our Permian Basin long-haul pipeline, primarily flows on basin pipeline to Cushing.

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We remain focused on disciplined investments and our outlook is summarized on slide 10. This is consistent with our May guidance, and we do not anticipate any meaningful changes in our capital program for the balance of the year.

I also want to share a few comments on how inflation impacts our business. Generally speaking, our inflation impacts are more moderate than some of the other energy sectors. Our capital program is modest, and we have proactively managed some costs through earlier purchases of materials.

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On capital allocation, our framework remains consistent. We are generating meaningful free cash flow and increasing the allocation to equity holders, while reinforcing balance sheet strength and flexibility. Year-to-date, we have repurchased approximately $75 million of common units out of the up to $100 million or so earmarked for 2022.

Longer term, we will continue to be opportunistic with repurchases. We monitor our business outlook, leverage equity valuation and yield as well as disciplined future capital investment opportunities. A summary of our current financial profile is located on slide 11.

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Willie C. W. Chiang

Chairman & Chief Executive Officer

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Looking forward, we continue to build momentum into 2023, and Plains is very well positioned to generate meaningful cash flow to the benefit of our investors. Over the last few years, we've made solid progress on optimizing our assets completing our multiyear capital build-out, forming numerous strategic JVs, including the Plains Oryx Permian JV and continuing to improve our safety, environmental and sustainability performance.

Additionally, as we've detailed in our remarks, we've continued to improve our balance sheet and have increased capital return to unitholders. Given the acceleration of our deleveraging and improved financial flexibility, we plan on having discussions regarding our capital allocation framework with our Board of Directors, and I look forward to sharing additional thoughts with you in the coming quarters.

In summary, we've accomplished numerous initiatives over the last few years and we believe our business is very well positioned today and going forward. A summary of our execution and positioning as well as key takeaways from today's call are provided on slides 12 and 13.

With that, I'll turn the call back over to Roy to lead us into Q&A.

Roy I. Lamoreaux

Vice President-Investor Relations, Communications & Government Relations

Thanks, Willie. As we enter the Q&A session, please limit yourself to one question and one follow-up question and then return to queue if you have additional questions. This will allow us to address the top questions from as many participants as practical in our available time this evening. Additionally, our Investor Relations team plan to be available throughout the week to address additional questions.

Sheri, we're now ready to open the call for questions.

QUESTION AND ANSWER SECTION

Operator: Thank you. [Operator Instructions] Our first question will come from Jean Ann Salisbury from Bernstein. Please go ahead.

Jean Salisbury Q

Hi. Utilization on crude pipes to Corpus has been very high year-to-date, higher than Houston and Cushing. Do you forecast this staying for the foreseeable future? Or what could change that?

Willie Chiang A

Jean, this is Willie. We've articulated our system as being very flexible. So as we think about our system, we've got capacity down to the coast through Cactus 1, Cactus 2 in basin.

And the point I wanted to make is whether or not volumes are flowing directly down to Corpus, doesn't necessarily reflect the power of the business, because volumes can be going up to Cushing. Jeremy, do you want to cover some more details on your specific questions.

Jeremy Goebel A

Yeah. Jean, with regard to Corpus, the marginal demand right now is the international given the disruption of the supply chain for crude oil. So we would expect to see utilization to the most efficient export markets. Corpus is pricing at a premium to Houston to other export markets.

So naturally, the highest price is going to attract barrels plus the quality of the barrel. So I think we'll see more of that. But as those lines fill, it starts to lead to higher utilization in other markets. So as we get through this year, you'll see Corpus remain high, and then you'll see additions to other markets. You'll see some additional RAMs and other pipes next year. So this is step one because it's the highest price -- and so you'll see that. But as it fills the whole boat, we'll start to fill. So -- but to answer your question, yes, we would expect Corpus. It's pricing at a premium from a quality and a logistic standpoint.

Willie Chiang A

And Jean Ann, Willie again. As production continues to grow in the Permian as we expect it to, by definition, we expect more volumes to go into our long-haul lines and as you probably saw in one of the slides, we do have increases in our outlook for volumes that are flowing both in the long-haul intra-basin and some of the other systems.

Jean Salisbury Q

Noted to that. Is it fair to say though that you we would prefer a barrel on Cactus or Cactus II versus a barrel going to Cushing in terms of margin or just depends?

A

Based on ownership, we're kind of even the margins to Corpus has been better, but the margins at Cushing continue to balance and are getting higher, and there's more demand for that over the longer-term, as we'll see. But I'd see on an absolute margin standpoint just because of ownership of basin relative to the others, we're somewhat indifferent between the two on even if it's a slightly lower tariff to Cushing because we own 100% of the our basin capacity versus what effectively with the Eagle Ford JV is 75% and then 65% on Cactus II. So when you think of the economics, we're somewhat indifferent, but barrels moving customers have the full pipelines.

A

And back on the flexibility just to reinforce the point. Currently, as utilization increases in the pipelines, the tariffs will increase as well. As we shared last time, the forward market still has some pretty constructive spreads in there that we've been able to utilize.

So what we say today may change as we go forward. If you've got a much higher tariff to Cushing, obviously, the barrel going to Cushing may make more sense. But again, think of our system as a very flexible system that allows us to go to multiple markets.

Jean Salisbury

Q

Great. I'll leave it there. Thank you

A

Thanks, Jean Ann.

Operator: Thank you. One moment for our next question. That will come from the line of Keith Stanley with Wolfe Research. Please go ahead.

Keith Stanley

Q

Hi. Good evening. First, on the NGL segment, can you say how much of the guidance uplift in EBITDA for the year is volume driven versus margin? And then I'm curious, you've seen higher volumes through Empress. I know you're working on other commercial and debottlenecking activities. Could there be a lot more movement in terms of volumes and building out that business over time?

A

Yes. I'll let either Jeremy or Al give you a view on the difference between pricing and volume. I can tell you it was both. We had some unique events in the second quarter as far as weather problems in the Bakken that allowed more flows going that way, but the fundamental volumes are also higher.

And you are correct, Keith, as we think about Empress, we've got some low cost to bottlenecking opportunities there. And as we've shared with you before, we clearly are trying to optimize the entire complex commercially so that we can optimize more of that.

Jeremy or Al, do you want to talk about dollars?

A

Yes. Sure. So your direct question is based on where we forecasted our weighted average frac spread between hedging and market pricing, I think that's going to end up around 40% price 50% volume. For this year, that's a proxy. I don't necessarily have the exact on hand, but I think that's going to be very close.

As far as order flow capacity us and Pembina have the vast majority of the capacity in the Empress complex, essentially all of it. And we have some room for expansion through the systems, some optimization that we've recently announced. And so incremental order flows from west to east will largely go to Plains capacity from here on out.

So as incremental production comes on net of what gets exported to the West Coast. Those movements as long as the odds continue and as you create more demand out of the Marcellus [ph] move to other markets, you would expect more barrels -- more gas to go from the AECO markets that are lower priced than in US markets.

So effectively, that's the mechanism. It does compete some with Bakken production. So you've seen some of the uplift in the second quarter was due to weakness in Bakken production. But by and large, the anything that's moving west to east on the TransCanada system to full fill voids across that arm would go through that Empress complex and we have substantial capacity to meet that existing -- to extract additional NGL

Keith Stanley

Q

You know, Chris Chandler, you may talk about -- just generally speaking, we haven't finalized investment decisions on this, but we've got a number of things that we're trying to advance as far as debottlenecking Empress. Chris, you want to add about that?

A

Sure, Keith, this is Chris. What we really like about Empress is there's capacity on the gas system to move more gas through as Jeremy stated. There's capacity in the extraction plants themselves, the straddle plants to extract the NGLs today. So that provides some operating leverage and upside.

And then from a debottlenecking standpoint, it's really about where we fractionate the NGLs. So today, we fractionate a portion at Empress and we ship the rest over to our Sarnia, Ontario fractionator. That gives us access to both those markets, but we are evaluating projects to do additional fractionation of Empress to be able to distribute the purity products directly out of the Empress or the regional area instead of having to ship them and the associated cost over to the east into Ontario to further fractionate there. So a lot of opportunity around both capacity and efficiency and debottlenecking for that entire complex.

And Keith, the dollar value of this is measured in tens of millions, not hundreds of millions. So they're very low-cost, high-return opportunities if we proceed with them.

Keith Stanley

Q

Thanks. That's very thorough and helpful. Second, unrelated question. On the Inflation Reduction Act, you obviously have the unique structure with PAGP. What's your initial read on who knows if the bill will pass and the minimum tax component. But as it's written right now, what's your initial read on what it could mean for PAGP and if it would apply to that security or not?

A

Keith, this is Al. Our read would be, it would not apply. I believe that as contemplated, it's -- if you have income, net income over $1 billion. PAG doesn't -- is much smaller than that. So we do not believe it would apply. If you stand back, ultimately, we think our structure is an MLP. If corporate tax rates go up, the MLP obviously isn't an issue there. Ultimately, PAGP has a very large tax asset there that if the entity won't be paying corporate taxes for a while. But we think this issue with this minimum tax does not apply to PAGP.

Keith Stanley

Q

Great. Thank you.

Operator: Thank you. One moment for our next question, that will come from the line of Colton Bean with Tudor, Pickering, Holt. Please go ahead.

Colton Bean

Q

Afternoon. You mentioned the potential to increase equity returns a number of times. I know it's still early in the decision-making process. But at a high level, would you expect to see the equity allocation of excess free cash flow move toward 100%, if you drop towards the lower bound of your leverage range? Or is there also a potential to see the leverage range shift lower altogether?

A

Colton, I'd rather give you a more detailed update after we have some discussions with our Board. When we think about capital allocation, a couple of things. We actually -- we have an annual process that we have with our Board. It happens early in the year, usually, and we announced in April with the distribution increase in May.

With the progress that we've made on deleveraging and our momentum that we're building into 2023, it gives us an opportunity to look at this a little closer. And I think what you'll see is, as we go forward, it's going to be a lot of the things you mentioned, we're going to evaluate where we want our leverage ultimately. We expect to be at our target we migrate down a little further.

And then also, you can expect us to be to continue our discipline as far as CapEx and investments. And then the real question on capital allocation is the split between distribution increase and buybacks and I think you'll see that we will continue to support distribution increases. I won't give you specifics on that because again, we have to have some conversation with our Board. But I would expect that the buybacks will continue to be opportunistic.

Colton Bean Q

Understood. And then following up on the NGL discussion, are you also seeing any benefit from wider basis spreads, particularly that Easton movement to Sarnia or is it primarily the frac spread that's driving the upside?

A

The answer is all of the above. So, we do manage our sales similar to our hedging. So there's some will be locked in at fixed differentials, but there's always an opportunistic component we can accelerate sales into opportunistic sales. So we do sell forward at fixed basis differentials. But when markets are short, we certainly -- we have the ability to sell in Edmonton.

We have the ability to rail out of the infra facility. We have the ability to rail out of the sorry, the Sarnia facility or sell locally there. So there's a ton of flexibility in where we market and how. So for instance, if Sarnia is a better market, you can sell locally there. At Conway likes certain instances now we see that opportunity, we can wheel barrels to that location.

So, it's a very flexible system, Etain, we have similar capabilities across it of California short or other markets. So you'll see an absolutely optimized sale and basis. But by and large, the frac spread is the biggest component, but basis can be at times have real market structure changes that would incentivize us to move additional barrels to it.

Colton Bean Q

All right. I appreciate the detail.

Operator: Thank you. One moment for our next question, that will come from the line of Chase Mulvehill with Bank of America. Please go ahead.

Neel Mitra Q

This is Neel Mitra filling in for Chase. I wanted to understand the contracting opportunities for basin, Cactus 1 and Cactus 2. Just recently, given the high year-to-date volumes, are you seeing any attractive blend and extend opportunities?

Or is the timeline just too short lived with low Cushing inventories at basin and the strong international demand given the Russian-Ukraine conflict, if people need to see a wider basis for longer for you to extend? And what's the appetite for that?

Jeremy Tonet A

Thanks, Neel. This is Jeremy. What I would say is we are constantly in the market with our gathering customers with our long-haul customers and in those dialogues. So while spreads were $0.40, now $0.60, moving to $0.80 than $1.20, we've been watching that along the way. We didn't want to do any long-term deals at those periods.

The time for blend and extend is when the prices are short cast. Now they're flushed cash, so they really don't look at, when the, extends more of looking secure takeaway at an appropriate price. And so we're in advance with what's the appropriate price.

We're very active. There's been a lot of demand in extending some deals into Cushing or getting long-haul so we're in discussions around some Cushing contracts securing supply. We're in discussions around Corpus contracts.

When there's something to update, we absolutely will. But we're constantly managing the duration of our contracts and -- but we want to maximize the value. And we're confident in the production profile we have this year and the momentum next year.

There's a better time when the prompt is $0.60 to negotiate longer-term deals, but as we talked about in the last call, 2024, still staying around that $1.25 range with a premium for Corpus markets. And so we'll continue to look to optimize that space and have discussions with our existing shippers and other shippers as well. And...

Neel Mitra Q

Great. And...

Jeremy Tonet A

Go ahead, Neel. Sorry.

Neel Mitra Q

Yes. I just wanted to ask a follow-up to that, Jeremy. So a lot of your peers have talked about Midland to Heaton pipes, producers not utilizing them and actually paying deficiency fees to move to alternative locations, which are presumably Corpus and likely Cushing as well.

Given that you have interest in almost all of the long-haul pipes out of Midland, can you just describe in the current market, what's going on and maybe how that impacts where Plains' volumes are going?

Jeremy Tonet A

Yeah. What I would say is there's a lot of volatility in flat price and location differentials between Brent, TI, MEH, Midland, which creates a lot of difficulty in pricing barrels. So a lot of the election to not move to the end market is to sell at Midland.

People see opportunities to better to just clear at Midland can do that, especially with backwardation and long-haul shipments and exports that adds complexity. So it's a long-winded way to answer. It's a very complicated process to price cargoes.

So that's why you see a lot of volatility in people pricing because they can't find markets and with the backwardation, they have to hit the exact window and people are moving to substantial volumes.

So some are more equipped to have different markets, so they sell us Midland another person lose on the pipe. But as I said in the beginning, Corpus for the market for exports is proving to be more efficient. It has a better price and better quality, and you're seeing a lot of barrels move in that direction.

Houston is moving to substantial volume. There's just a lot of capacity to thereafter Wink-to-Webster, so you're seeing some more slack there. But pricing these things is complex and you'll see a lot of cargoes moving a few days in a month, and then you won't see any move for a period when the prices get out of whack. So it's a constantly fluid situation, but price usually wins and right now, corporate is the best price with low inventories and high crack spreads. Cushing has to move barrels. So you've seen some more demand on the basin system, there's not inventories to pull from. And then the Houston refining and the base export business, you're seeing pretty consistent volumes you're just seeing a displacement of volume from one type to the other.

A

And Neil, the key takeaway on this that Jeremy has been talking about is, remember, we've got strong MVCs on these lines. So whether or not a volume flows there or not, we still get paid and it gives us the opportunity to further optimize it.

Neel Mitra

Q

Right. Appreciate all the color. Thanks.

Operator: Thank you. One moment for our next question. Our next question will come from the line of Brian Reynolds with UBS. Please go ahead.

Brian Reynolds

Q

Hi good evening everyone. You talked about in your prepared remarks running 10% above expectations, I think, on a volumetric perspective. Kind of curious if you can just talk about how you're attracting volumes to system. And if you could help bifurcate what you're seeing from organic growth and perhaps attracting new volumes and customers to the system from competitors? Thanks.

A

I'm going to let Jeremy answer this, but I want to preface it with -- it's a very complicated system. And because we've got the gathering JV, we've got intra-basin, we've got long haul. There's a lot of moving parts on this. So Jeremy, take a shot at it.

A

Sure. Brian, first answer to clarify what really was saying is a 10% increase in activity across the system. Activity translates to volumes later in the year. So for instance, we think the production growth is back in weighted. Connections are 40% in the first half, roughly 60% in the second half. So that activity is going to yield some momentum in the second half of the year going into 2023. So I just wanted to first clarify that.

But how are we doing competing for volumes. We have over 4 million dedicated acres between the ports and claims systems, the POP JV that we have. We continue to have happy customers and our extending deals. We're actually adding substantial acreage to the physician core acreage for a significant term, so I think we're competing very well, and we're not pricing to the lowest common denominator due to the flexibility, the quality control and the market access that we have on the system.

So what I would say is that, we're competing very well for incremental and organic volume. But when you have term acreage dedication, you have contracts that bring a substantial amount of activity to the system. So not everything has to be organically developed when you have the contract tenure that we have. This is just additive to the base business that we put together when we merged the two businesses.

A

I think, Brian, if you look at slide seven, it would probably give you a little more insight in the volumes and how we're getting it across the system in the Permian between gathering interbasin long haul.

Brian Reynolds

Q

Great. Appreciate all that clarification extra color. Just my one follow-up. Could you just talk about what you're seeing in terms of Eagle Ford volumes saw a small tick down during the quarter, but it seems like you heard attracting more rig count and activity to the system. I'm kind of curious if you can talk about further expectations there. Thanks.

A

Jeremy?

Jeremy Goebel

A

Sure, Brian. You've seen a lot of turnover from public operators to private operators in the Eagle Ford and that generally leads to more activity because those activities were starved for capital given that there was more allocation to the Permian or somewhere else.

And so you've seen Chesapeake say, it's non-core. So I would say is we have seen more activity the newer buyers come in and they're accelerating activity. We've seen that in the Western Eagle Ford with the Chalk as well as the Lower Eagle Ford. So I'd say, we are seeing an increase in activity in the Eagle Ford, and it seems to be -- as they prove up the Chalk in the Western Eagle Ford, we would expect to see continued growth in volume there.

Brian Reynolds

Q

Good. Appreciate all the color. Have a good rest of the evening everyone.

A

Thanks, Brian.

Operator: Thank you. One moment for our next question. That will come from Jeremy Tonet with JPMorgan. Please go ahead.

Jeremy Tonet

Q

Hi. Good afternoon.

Willie Chiang

A

Good afternoon.

Jeremy Tonet

Q

Thanks. Just want a quick refresher, if I could. I think you talked about in the past points where volume growth on the system would [indiscernible] MVCs and it would turn into more fault of the bottom line beat growth at that point. Do you -- what's the current time line there? Does that move forward at all with this? Or just a refresh there would be great.

Willie Chiang

A

I think the refresh would be, Jeremy, you look at our numbers for the quarter and the additional volumes we've been able to bring in. The system is flexible -- the gathering system grows with the basin. So those volumes continue to grow. And then on the long haul, you'll see that the long haul volumes, we've been able to get some more volumes on that.

And the difference between last quarter's estimate and this quarter's estimate, which is on the slide really shows the increase in the system. Jeremy, anything to add?

Jeremy Goebel

A

No. Jeremy, I think Willie is right as you accelerate production and momentum, you bring that time period forward, as we said, every time you add 600,000 or 700,000 barrels a day of production, you're filling the pipe. So if you think about that, it's still consistent with the 18 to 24 months that we talked about, but it's accelerating as we accelerate our forecast, and we feel good about the momentum going into next year.

And then proving out, as you look at the differentials to the coast, they're getting outside of tariffs beginning in 2024. So it's very consistent with what we said, and it's continuing to progress along and we're looking forward to that period.

Jeremy Tonet Q

Got it. So someone together, maybe that's a mid 2023 timeframe, if it's slightly quicker than before, from kind of ballpark it?

Jeremy Goebel A

Sure. I mean that's a very reasonable estimate. I say you can get into that period and you start to see a better utilizations and it strikes a better balance between the carriers and the producers for a reasonable rate return. I'd say, you can get into that period and you start to see a better utilizations and this strikes a better balance between the carriers and the producers for a reasonable rate of return on the pipe

Willie Chiang A

But Jeremy, just to make sure we're saying the same thing. I agree with what Jeremy Goebel said, but our system because of the flex allows us to capture some of the -- we don't have to wait for that period of time to be able to capture volumes. I hope that's clear.

Jeremy Tonet Q

Got it. Thanks. And just one last one, if I could. If I'm looking at the guidance increase now versus May, how -- what's the breakdown between fee versus commodity there?

Willie Chiang A

It's a tough -- Alan, can you give the numbers, they're all tied to higher commodity prices, but there's definitely some line components of it.

Alan Swanson A

Yes, there's one slide that we did a walk for the year -- from the beginning of the year. But most of the driver is commodity, whether it's the NGL frac up in Canada, as Jeremy mentioned earlier, we are seeing some volume benefit there as well.

And then on the crude oil side, which has actually been a smaller part of the increase, it's driven by the PLA pricing, but also this Permian volume growth that we're seeing and is embedded in. So I would say, over half of it is more commodity based and the rest, I would say, would be more fee-based.

Jeremy Tonet Q

Got it. I'll leave it there. Thank you.

A

Thanks, Jeremy.

Operator: Thank you. One moment for our next question, that will come from the line of Sunil Sibal with Seaport Global. Please go ahead.

Sunil Sibal

Q

Yes. Hi. Good afternoon, folks, and thanks for all the clarity and the call. A couple of questions for me, starting out on your asset sales program, the updated number, $200 million. Is that entirely a function of bringing more assets into the program? Or is this a function of the market also?

A

It's really developing better clarity on what assets we've been visiting with folks about different assets, and it's just more clarity on being able to bring that across the line this year, Sunil.

Sunil Sibal

Q

Okay, got it. And then I think you folks mentioned about some impact of the outages in Balkan, in terms of your NGL assets in Canada. I was kind of curious, have you seen that abate? Or that's something you're kind of still expecting a benefit from the remainder of the year?

A

Jeremy?

Jeremy Goebel

A

Sunil, hi. This is Jeremy. So as the Williston production went down, gas and crude oil production -- gas production went down that normally feeds to the Midwest. So, more gas was needed from ACO storage. So that was temporal in April and May. But we're still seeing high order frozen high production. Canadian production is approaching 14 Bcf a day.

We've got April prices hovering between $4 and $5, which is in sending additional drilling. So those are all positive for incremental order flow. So that portion is sustained. But just some portion of April, May, the second quarter outperformance was driven by that, but a substantial portion was driven by better activity in the gas plays within Canada.

Sunil Sibal

Q

Okay. Got it. Thanks for that.

A

Thanks, Sunil.

Operator: Thank you. One moment for our next question, that will come from the line of Neal Dingmann with Truist. Please go ahead.

A

Hi, Neal.

Neal Dingmann

Q

Thank you, guys. Good evening, guys. Thanks for the time. My first question is on M&A and specifically, was curious as how do you view today's market of existing potential available assets versus -- I know you've got a lot of room for potential expansion or other -- what I consider sort of organic type build-out. I wonder how you sort of view these two things.

A

Well, we look at a lot of assets that are out there, and we're going to stay very disciplined on it. But the bid ask spread, I would say, is coming in a bit, Jeremy?

Jeremy Goebel

A

Sure. On the crude side, the market side of the deep it's on the liquids or the gas side, but we're going to remain disciplined, and we'll see opportunities that the footprint we have affords us an ability to extract more synergies than most from a capital standpoint, from an operating expense standpoint and from a commercial standpoint. So we'll be disciplined, we'll look for opportunities. We're constantly gain dialogue, but we're only going to do things if they're near-term cash flow accretive and longer-term beneficial for the overall system.

Neal Dingmann

Q

Great to hear. And then just a quick second one. I'm just trying to get a broad sense of how much of the total intrapatient Permian growth. I know you mentioned there a good bit of this is likely to be coming from that recent Advantage JV. I'm just trying to get a sense in broad terms, is it more for housekeeping? Is that a large percent? Or just trying to get an idea of how much that Advantage will be contributed?

A

To give you a sense Advantage 50% that we acquired was roughly 30,000 to 35,000 barrels a day. That will give you a sense from a gross basis what will come back to us. But we have the ability to move barrels from other directions and put them on that pipe.

And eliminate future capital expenditure moving from west to east by replacing those volumes. So I think we had the ability to put additional volume and eliminate or defer significant capital expenditures. So I think that's part of the orders to have that idle capacity that we can use to more efficiently operate our system.

Neel Mitra

Q

Great details Jeremy. Thank you, guys.

Jeremy Tonet

A

Thanks, Neel.

Operator: Thank you. I'm showing no further questions in the queue at this time. I would now like to turn the call back over to management for any closing remarks.

Roy I. Lamoreaux

Vice President-Investor Relations, Communications & Government Relations

Thanks, Sheri. Well, listen, thanks to everyone for joining us today. We look forward to visiting with you going forward. And thanks for your continued interest and support for Plains All American. Have a nice evening.

Operator: This concludes today's conference call. Thank you for participating. You may now disconnect -- disconnect.

2Q22 Earnings Call

August 3, 2022

PLAINS

Forward-Looking Statements & Non-GAAP Financial Measures Disclosure

- This presentation contains forward-looking statements, including, in particular, statements about the performance, plans, strategies and objectives for future operations of Plains All American Pipeline, L.P. ("PAA") and Plains GP Holdings, L.P. ("PAGP"). These forward-looking statements are based on PAA's current views with respect to future events, based on what we believe to be reasonable assumptions. PAA and PAGP can give no assurance that future results or outcomes will be achieved. Important factors, some of which may be beyond PAA's and PAGP's control, that could cause actual results or outcomes to differ materially from the results or outcomes anticipated in the forward-looking statements are disclosed in PAA's and PAGP's respective filings with the Securities and Exchange Commission.

- This presentation also contains non-GAAP financial measures relating to PAA, such as Adjusted EBITDA attributable to PAA, Implied DCF and Free Cash Flow. A reconciliation of these historical measures to the most directly comparable GAAP measures is available in the Investor Relations section of PAA's and PAGP's website at www.plains.com, select "PAA" or "PAGP," navigate to the "Financial Information" tab, then click on "Non-GAAP Reconciliations." PAA does not provide a reconciliation of non-GAAP financial measures to the equivalent GAAP financial measures on a forward-looking basis as it is impractical to forecast certain items that it has defined as "Selected Items Impacting Comparability" without unreasonable effort.

2Q22 Earnings Call Highlights & Outlook

Constructive Crude / NGL fundamentals, building momentum into 2023

- **Strong Q2 Adj. EBITDA[1] $615MM:**
  - Benefit of higher straddle plant volumes, elevated commodity prices (crude PLA) & increased Permian volumes
- **Raised 2022 Adj. EBITDA(G)[1] to +/- $2.375B**
  - +$100MM vs. May(G): +$55MM NGL, +$45MM Crude
  - +$175MM vs. Feb(G): +$105MM NGL, +$70MM Crude
- **Accelerated YE-22 deleveraging[2] +/- 4.00x (mid-point of target range)**
- **Opportunistic Equity Repurchases ~$50MM: $300MM since Nov-20 authorization**
- **Increased Asset Sales expectations to +/- $200MM: +$100MM vs. May(G)**
- **Permian JV acquired remaining 50% ownership interest in Advantage JV for ~$65MM[3] or ~$42MM net to PAA**
- **Published 2021 Annual Sustainability Report ([Link])**

2022(G): Furnished August 3, 2022. May(G): Furnished May 4, 2022. Feb(G): Furnished February 9, 2022
(1) Attributable to PAA. (2) See Definitions. (3) Plus customary closing costs.
Please visit https://ir.paalp.com for a reconciliation of Non-GAAP financial measures reflected above to most directly comparable GAAP measures.

Positioned to Increase Unitholder Returns

Financial Flexibility

- 2022 Adj. EBITDA(G)[(1)]: +$175MM vs. Feb(G)
- On track to achieve leverage[(2)] target (4.0x) by YE-22
- Increasing returns of capital to equity holders

Permian Production

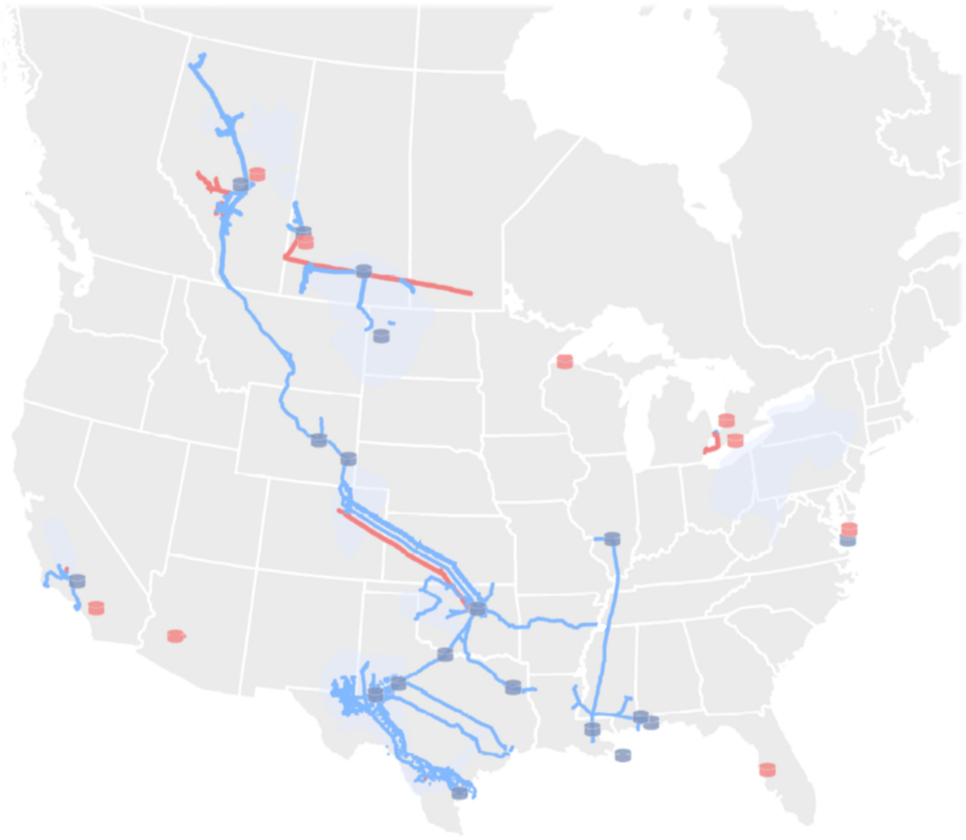
- Expect 650 - 700 Mb/d of growth in 2022 (exit-to-exit)
- Building momentum into 2023
- 2025: ≥7 MMb/d of total production

Operating Leverage

- Multi-year asset buildout complete
- Meaningful available crude & NGL capacity with minimal capital needs, capturing incremental growth

System Optimization

- Closed bolt-on acquisition of Advantage JV
- Increased 2022 Asset Sales Target +$100MM to $200MM
- Advancing NGL debottlenecking opportunities



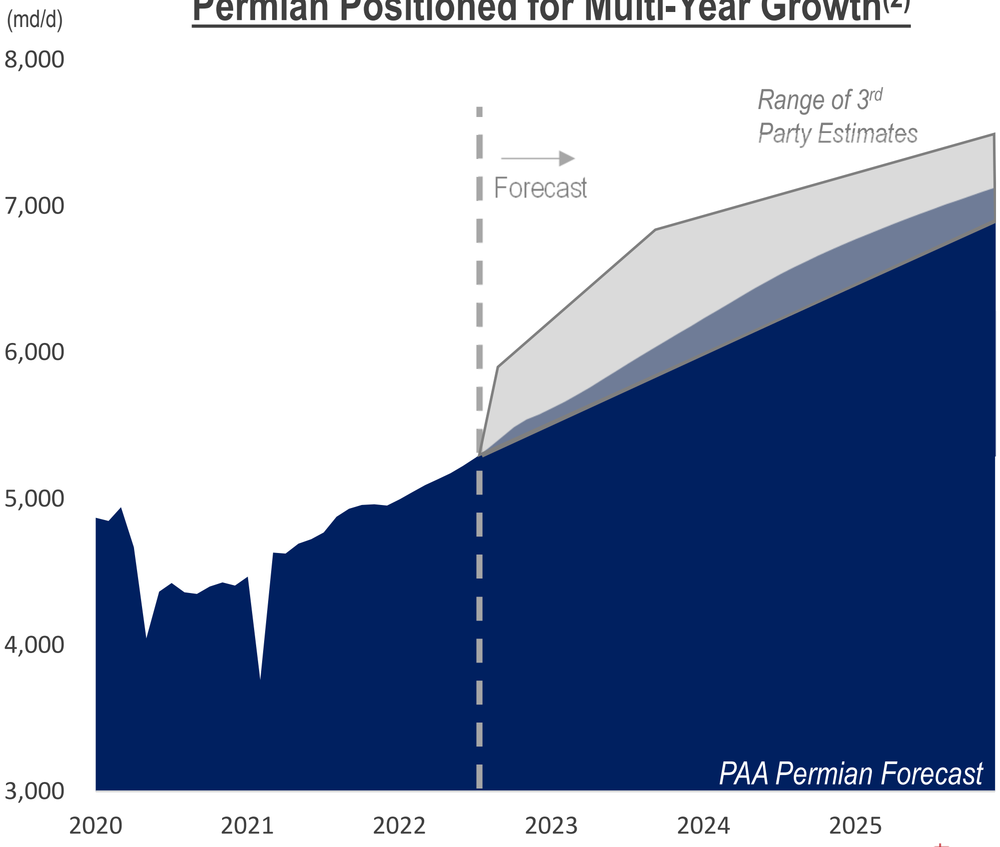
2022(G): Furnished August 3, 2022. Feb(G): Furnished February 9, 2022
(1) Attributable to PAA. (2) See Definitions.

Permian Activity Tracking Higher

Building momentum into 2023

- **Total Permian Basin crude oil production currently estimated to be ~5.3 MMb/d[1]; For 2022:**
  - PAA currently estimates 650 – 700 Mb/d of growth (exit-to-exit)
  - 3rd Party growth estimates range from 500 – 1,000 Mb/d (exit-to-exit)
- **Activity is currently trending ~10% above initial expectations**
  - Expected to have minimal impact in 2022; builds positive momentum into 2023 production estimates
- **Expect additional ramps in activity to continue, but expect pace to be moderated by supply chain, manpower & equipment limitations**

Permian Positioned for Multi-Year Growth[2]



(1) Source: EIA (2) Source: PAA Estimates, other non-public 3rd party sources.

2022(G): Financial Metrics

Increasing EBITDA, generating meaningful FCF & coverage, achieving leverage targets

($ millions, except per-unit metrics)

Adjusted EBITDA / DCF

Segment Adjusted EBITDA	May(G) (+/-)	Aug(G) (+/-)
Crude Oil	$1,845	$1,890
NGL	430	485
Other Income	-	-
Adj. EBITDA attributable to PAA	**$2,275**	**$2,375**
Implied DCF to Common	$1,450	$1,550
Implied DCF / CUE[1]	$2.08	$2.20
Distribution Coverage (Common)[2]	250%	265%
Year-End Leverage Ratio[1]	4.25x	4.00x

Cash Flow

	May(G) (+/-)	Aug(G) (+/-)
Cash Flow from Ops (CFFO)[1]	$1,950	$2,050
Asset Sales	$100	$200
FCF[1]	$1,250	$1,400

Capital (Consistent with May(G))

	Aug (G) (+/-)	
	Net to PAA	Consolidated
Investment	**$275**	**$330**
Permian JV	$110	$165
Other	$165	$165
Maintenance	**$210**	**$220**
Total	**$485**	**$550**

2022(G) / Aug(G): Furnished August 3, 2022. May(G): Furnished May 4, 2022.

(1) See Definitions. (2) Distribution Coverage reflects cash distribution per common unit paid in February and the increased annualized distribution rate of $0.87 per common unit for the remainder of the year.

2022(G): Operational Metrics

Capturing incremental long-haul barrels, Gathering growth consistent with May(G)

(table data reflects full-year averages)	*May (G) (+/-)*	*Aug (G) (+/-)*	Δ
Crude Oil Segment			
Crude Pipeline Volumes (Mb/d)	**7,330**	**7,410**	***+80***
Permian	**5,365**	**5,490**	***+125***
Gathering	2,375	2,375	-
Intra-Basin	1,955	2,000	*+45*
Long-Haul	1,035	1,115	*+80*
Other	**1,965**	**1,920**	*(45)*
Commercial Storage Capacity (mmbbls/mo)	72	72	-
NGL Segment			
NGL Sales (Mb/d)	140	140	-
C3+ Spec Product Sales[(1)]	50	55	*+5*
Fractionation Volumes (Mb/d)	125	135	*+10*

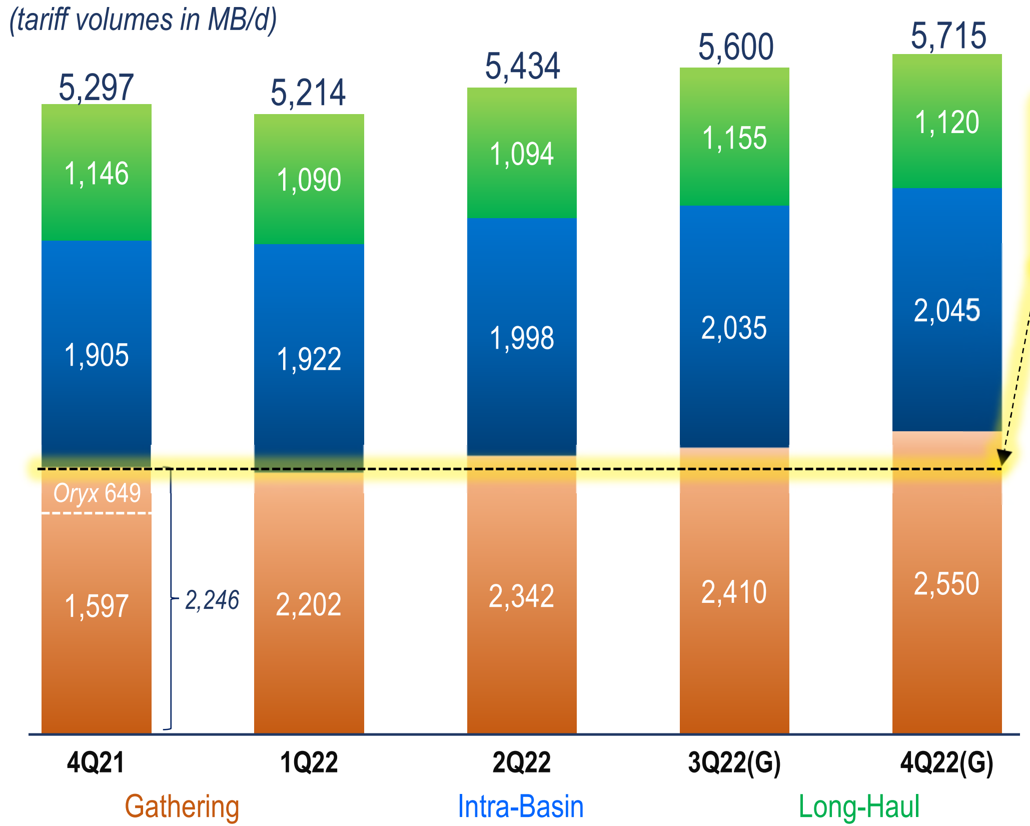
Includes benefit of Advantage JV bolt-on & increased long-haul flows to Cushing & Corpus

Increased straddle production driving higher fractionation volumes & C3+ Spec Product Sales

2022(G) / Aug(G): Furnished August 3, 2022. May(G): Furnished May 4, 2022. Note: Permian JV volumes on a consolidated (8/8ths) basis. See Definitions.
(1) C3+ sales on this slide refers to the sale of spec C3, C4 and C5+ exposed to frac spread.

Permian Gathering & Intra-Basin Driving Volume Growth

Permian building momentum, additional volumes added since May(G)



4Q22(G) vs. 4Q21: ↑420 Mb/d

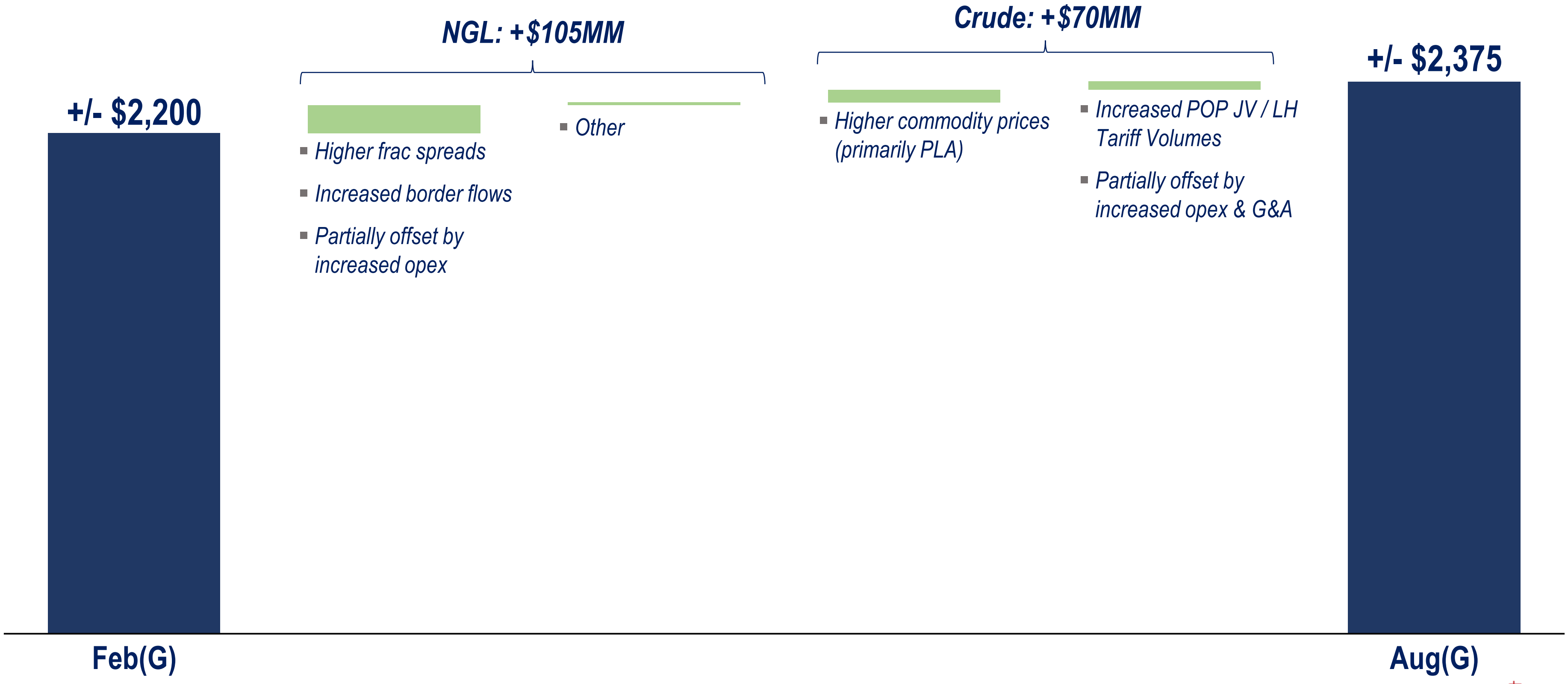
- **Gathering: ↑ 305 Mb/d**
  - Tracking in-line with expectations
- **Intra-Basin: ↑140 Mb/d**
  - Benefitting from Advantage JV bolt-on in 2H22
- **Long-Haul: ↓25 Mb/d**
  - Increased demand-pull volumes via Basin to Cushing in 2Q22
  - Actively working to secure additional volumes on PAA's long-haul assets

2022(G): Furnished August 3, 2022. May(G): Furnished May 4, 2022.
Note: Permian JV volumes on a consolidated (8/8ths) basis. See Definitions.

2022 Key Drivers: Feb(G) vs. Aug(G)

Increased volumes & higher commodity prices driving full-year outlook higher

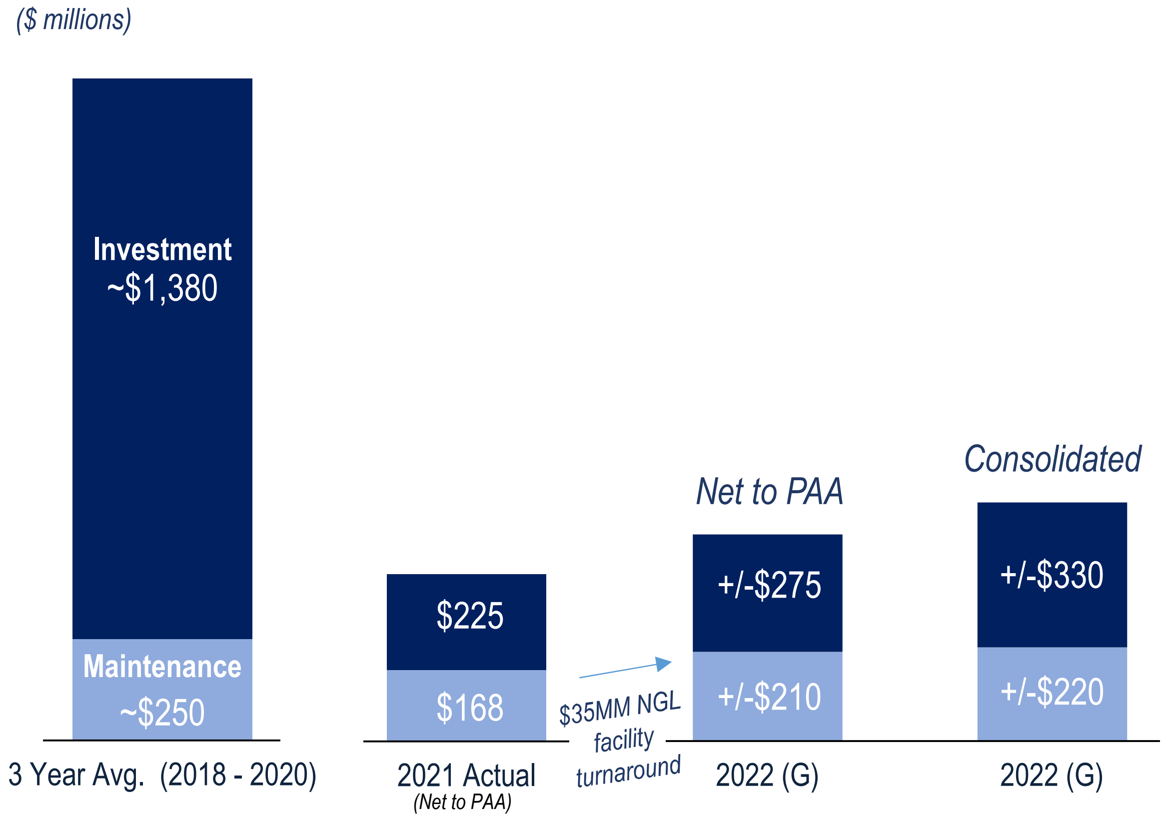
(Adj. EBITDA attributable to PAA, $ millions)



Aug(G): Furnished August 3, 2022. Feb(G): Furnished February 9, 2022.

Disciplined Capital Investment (Consistent with May(G))

Multi-Year Buildout Complete, Focused on High-Return Investments



- **2022(G) Investment Capital: $330MM**
  - ~50% Wellhead & CDP Connections (paced w/ producer activity levels)
  - Capturing capital synergies through Permian Gathering JV
- **Consolidated Run Rate Maintenance(1): <$200MM**

2022(G) and Run Rate: Furnished August 3, 2022. May(G): Furnished May 4, 2022. (1) Average annual estimate: annual amount may be impacted by timing and/or turnaround projects.

Current Financial Profile

Expected YE-22 Leverage Ratio: +/-4.00x

	12/31/21	6/30/22	Target
Balance Sheet			
Cash & Equivalents	$449	$267	
Short-Term Debt	822	630	
Long-Term Debt	8,398	7,986	
Total Debt	**$9,220**	**$8,616**	
Adj. EBITDA (LTM)(1)	**$2,196**	**$2,306**	
Credit Stats & Liquidity			
Leverage Ratio(2)	**4.5x**	**4.1x**	**3.75x - 4.25x**
Committed Liquidity ($ bln)	$3.0	$2.8	
Investment Grade Balance Sheet	BBB- / Baa3		

2022(G): Furnished August 3, 2022.
(1) Attributable to PAA. (2) See Definitions.
Note: Please visit https://ir.paalp.com for reconciliation of Non-GAAP financial measures reflected above to most directly comparable GAAP measures.

Multi-Year Execution Builds Momentum Into 2023

Meaningful progress towards long-term goals

Asset Base

- ✓ Completed multi-year capital buildout
- ✓ Formed 15+ strategic JVs, including Plains Oryx Permian JV
- ✓ Improved Safety & Environmental performance >50% & ~40% since 2017, respectively
- ✓ Reduced GHG emissions in last 4 years

Balance Sheet

- ✓ Investment grade balance sheet
- ✓ ~$4.5B in asset sales since 2016
- ✓ Reduced debt >$1.5B since YE-20
- ✓ Improved financial flexibility

Capital Allocation

- ✓ Self-funding routine capital program
- ✓ Repurchased ~$300MM of common units
- ✓ Increased distribution $0.15/unit in May 2022
- ✓ Capacity to increase equity returns as leverage decreases (265% coverage)

2Q22 Earnings Call Key Takeaways

Constructive fundamentals, capturing Permian growth

- **Solid 2Q22 results & execution**
- **Increased 2022 Adj. EBITDA(G)[1] by $100MM to +/- $2.375B**
- **Expect to achieve midpoint of leverage target[2] by YE-22**
- **Fundamentals constructive, building momentum into 2023+**
- **Positioned to generate significant FCF with meaningful capacity to increase returns of capital to equity holders (265% Coverage)**

2022(G) : Furnished August 3, 2022.
(1) Attributable to PAA. (2) See Definitions.

Appendix

Incremental Updates:

- Segment Adj. EBITDA Walks
- Financial & Operational Updates
- 2021 Sustainability Report Highlights

Overview of 2022 Goals

- Run a safe, reliable and responsible operation
- Generate meaningful Free Cash Flow
- Strengthen balance sheet / financial flexibility
- Increase returns to equity holders

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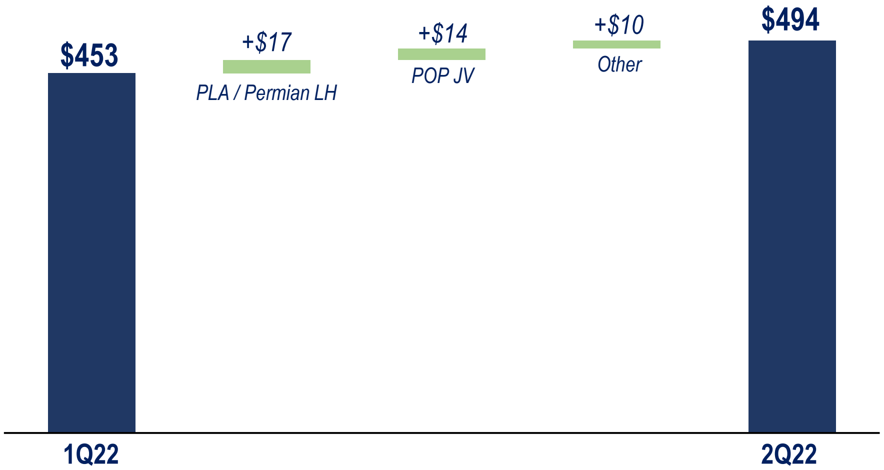
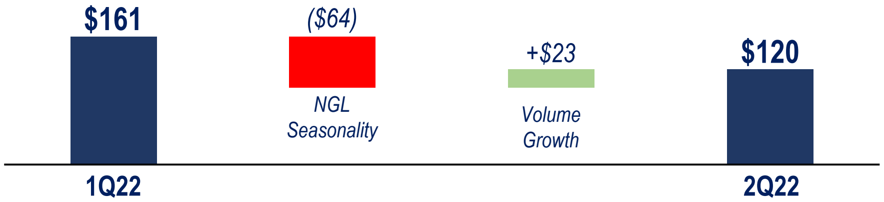
Key Drivers: 1Q22 to 2Q22

($ millions)

Crude Oil Segment Adjusted EBITDA



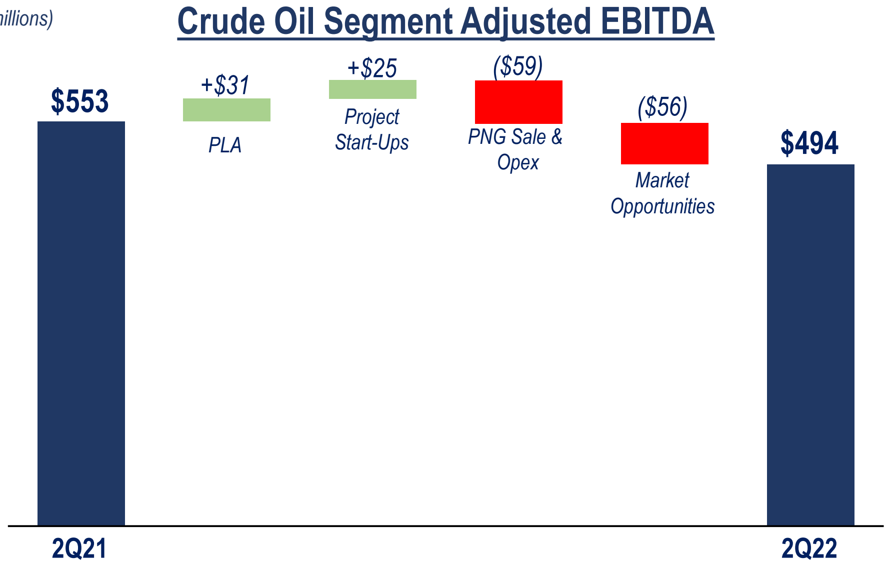
NGL Segment Adjusted EBITDA

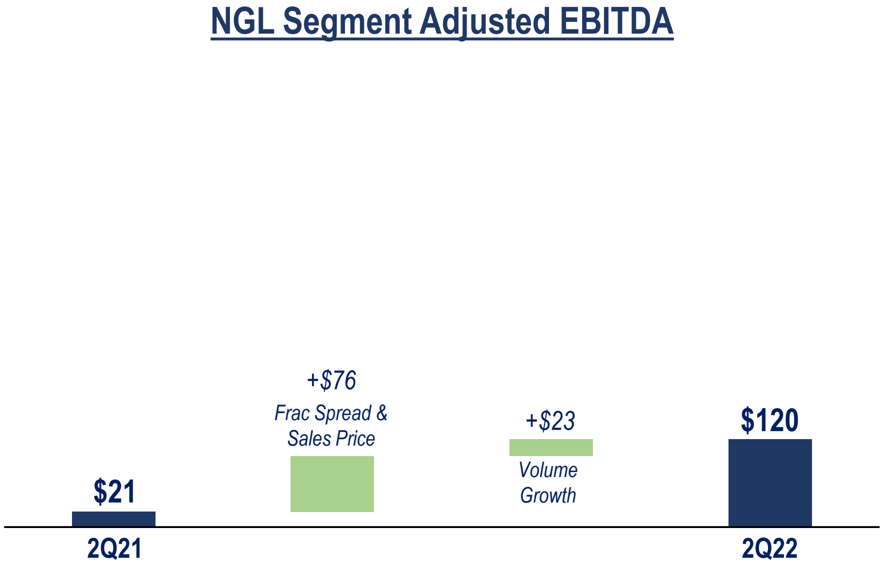


- **Crude Oil Segment**
  - **PLA / Permian LH:** benefit of higher commodity prices; increased LH volumes, offset by MVC deficiency payment received in 1Q22
  - **POP JV:** increased volumes on JV gathering systems
  - **Other:** market-based opportunities partially offset by higher opex resulting from increased utilities & personnel expense
- **NGL Segment**
  - **NGL Seasonality:** primarily lower sales volumes & margin versus seasonally stronger winter quarter
  - **Volume Growth:** additional border flows into the Empress straddle plant as a result of increasing Canadian gas production & weather outages

Key Drivers: 2Q21 to 2Q22

($ millions)





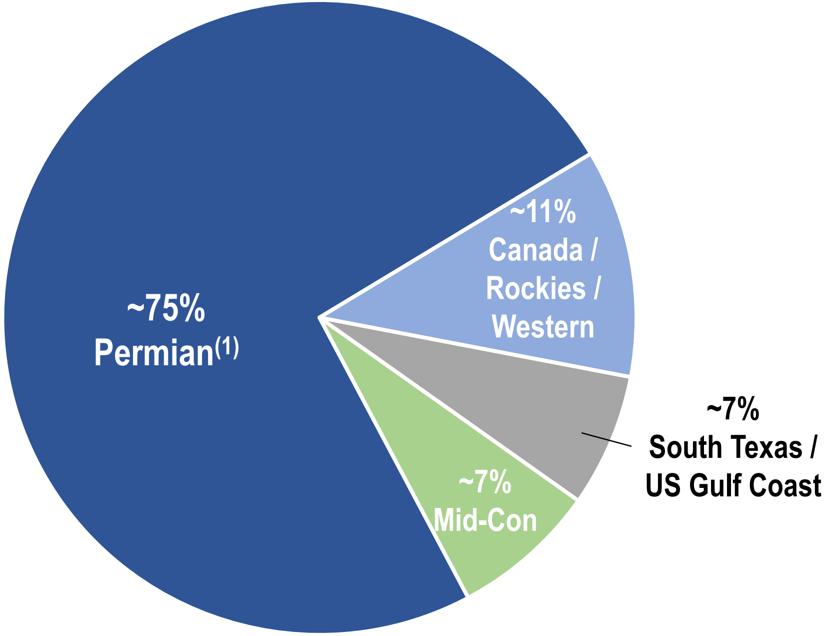
- Crude Oil Segment
  - **PLA:** benefit of higher commodity prices
  - **Project Start-Ups:** primarily start-up of Capline & W2W
  - **PNG Sale & Opex:** 2Q21 benefit of PNG operations & 2Q22 increased opex from higher volumes
  - **Market Opportunities:** 2020 contango opportunities realized in 2021 partially offset by 2Q22 market-based opportunities

- NGL Segment
  - **Frac Spread & Sales Price:** benefit of higher commodity prices
  - **Volume Growth:** additional border flows into the Empress straddle plant as a result of increasing Canadian gas production & weather outages

Crude Oil Segment 2022(G): +/- 80% of Adj. EBITDA

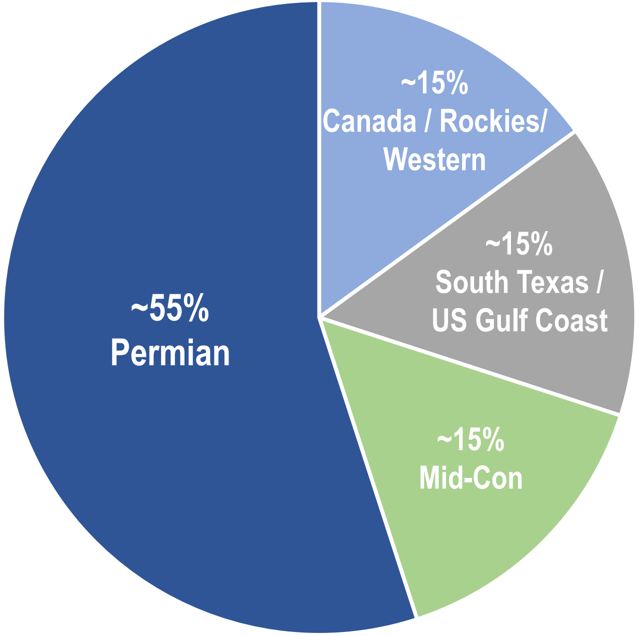
Regional Detail

2022(G): 7,410 Mb/d Pipeline Volumes



2022(G): $1,890MM Adj. EBITDA(2)

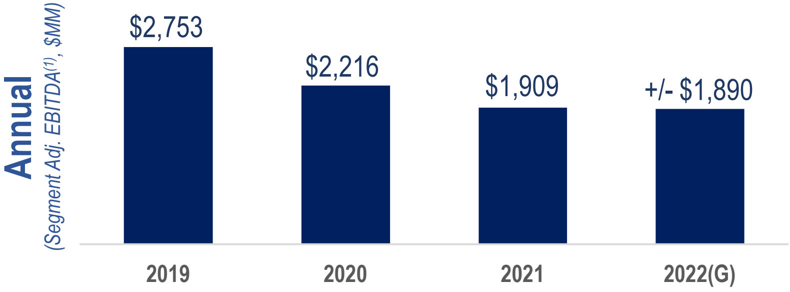
Includes +/-$200MM from Storage Terminals(3)

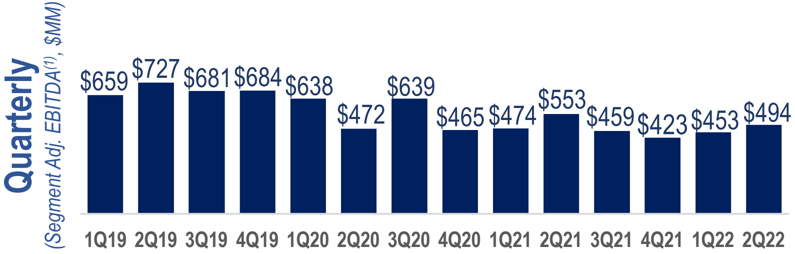


2022(G): Furnished August 3, 2022. (1) Includes consolidated Permian JV volumes. (2) Attributable to PAA.
(3) Terminals include Cushing, Patoka, St. James, and Others. Majority of EBITDA associated to terminals in Mid-Con and South Texas / Gulf Coast regions.

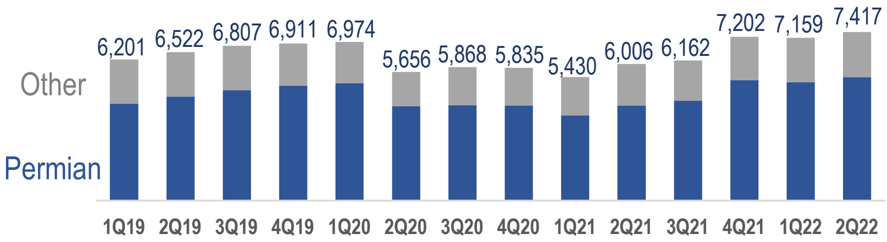
Crude Oil Segment Detailed Data (2019 – 2022)

- **Crude Oil Segment Considerations / Context:**
  - COVID-19 production reset - L48 onshore ↓ >2MMB/D from Mar-20 peak, competitive market dynamics
  - Outsized margin capture 2019 – 2021; not expected to continue in 2022
  - ~$1.4B in non-core / strategic JV asset sales since 2019

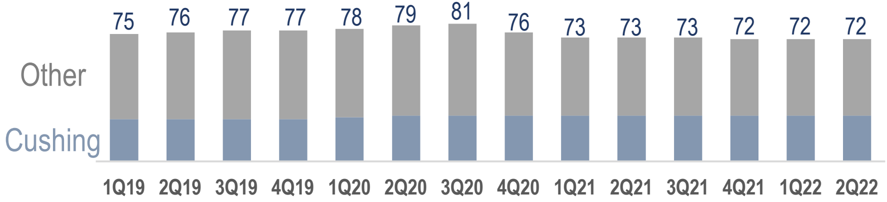




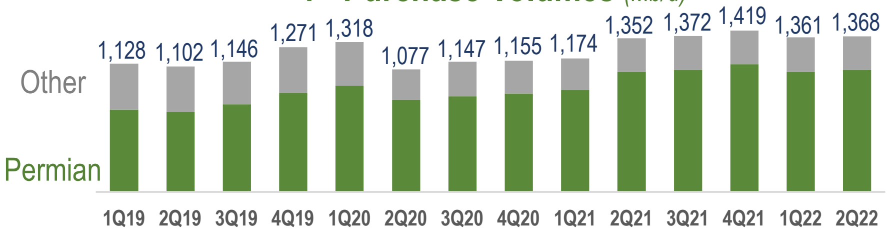
Pipeline Tariff Volumes[2] *(Mb/d)*



Storage Capacity *(MMbbls/mo)*



1st Purchase Volumes *(Mb/d)*

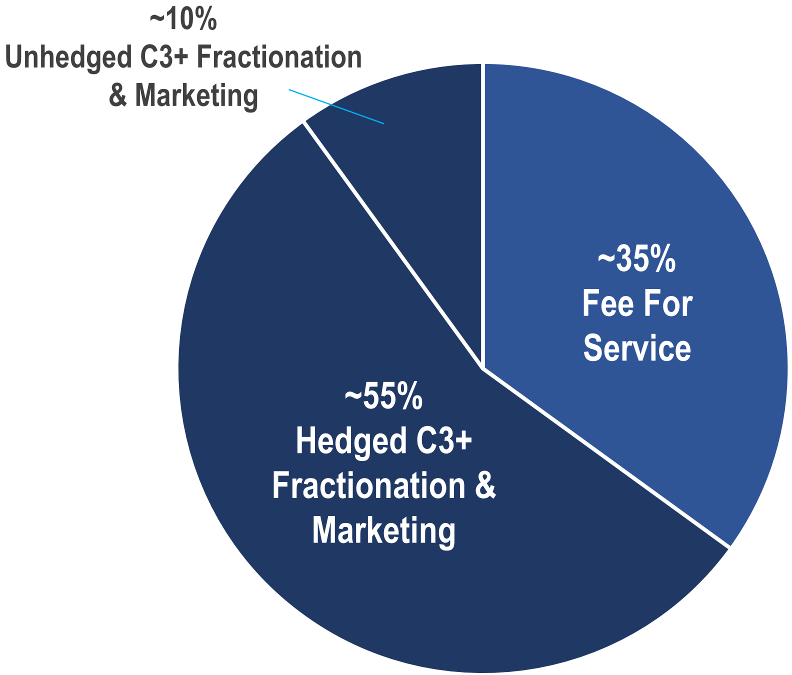


2022(G): Furnished August 3, 2022.
(1) See Definitions. (2) Excludes trucking.

NGL Segment 2022(G) Detail: +/- 20% Total Adj. EBITDA

- **Majority of EBITDA generated by C3+ frac spread benefit**
  - Hedge frac spread (12+ months rolling)
  - Purchase AECO nat gas & sell spec products (C3+) on Mont Belvieu pricing[1]
  - ~55 Mb/d of total NGL sales benefit from Frac Spread
- **Fee-for-Service**
  - Third-party throughput[2]: fractionate, store, and transport (~45 Mb/d not included in reported NGL sales)
  - Net purchased volume (purity and Y-grade): transport, fractionate, store & sell (~45 Mb/d)
  - Ethane: cost recovery model (~40 Mb/d)

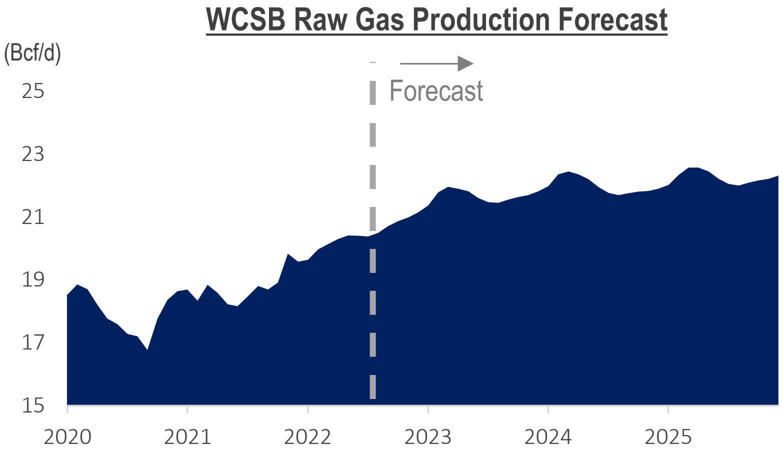
2022(G): $485MM Adj. EBITDA[3]

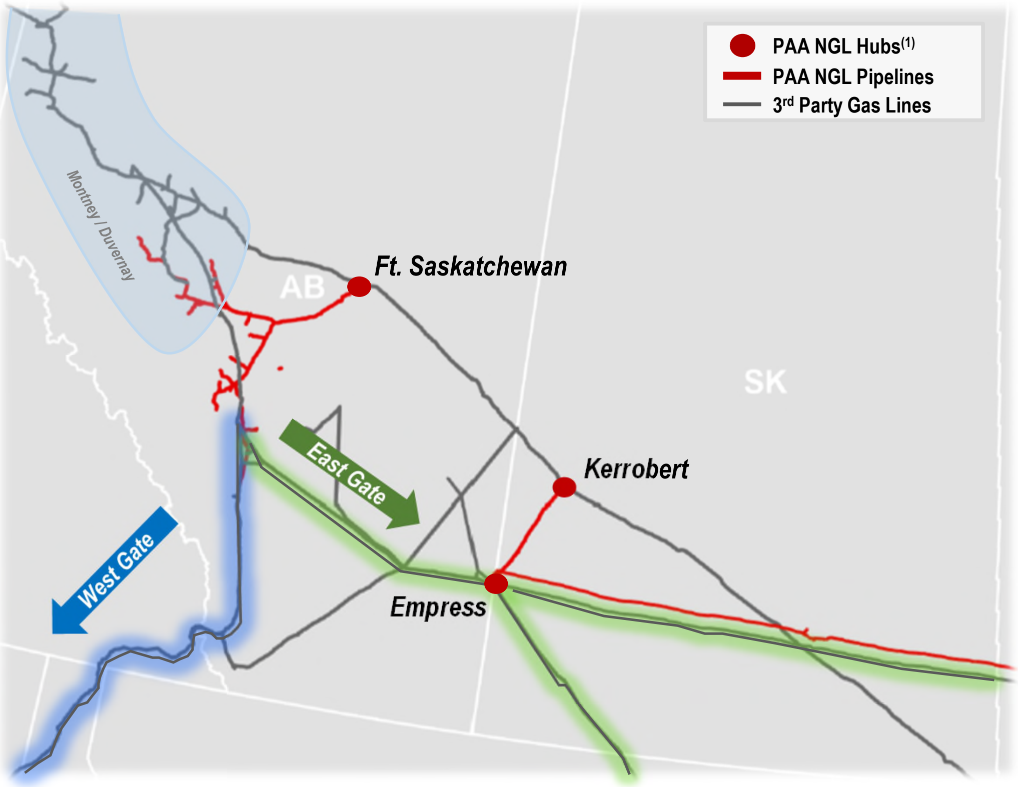


2022(G): Furnished August 3, 2022.
(1) Exposed to basis pricing differentials (2) Buy / Sell agreements with 3rd parties. (3) Attributable to PAA; Earnings profile can be impacted by timing of product lifting / sales.

Increasing Canadian Gas Production & Limited West Gate Capacity Benefitting Plains' Empress Facility

- **Constrained West Gate takeaway capacity driving volumes east towards Empress & Sarnia**
  - Able to extract additional y-grade at our Empress Facility & benefit from current frac spread environment
- **Increasing gas production & border flows drives increasing utilization of PAA facilities**



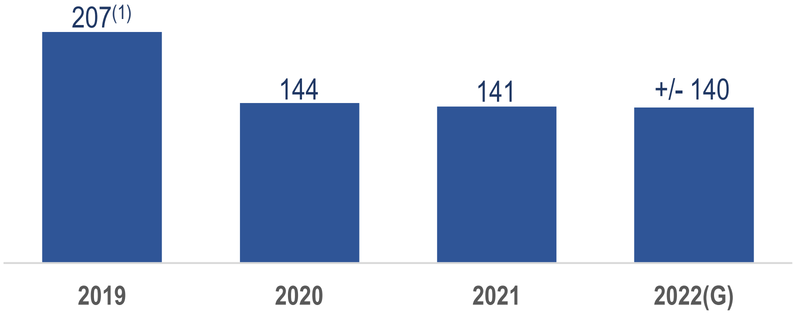


Source: PAA Estimates (1) Not all PAA NGL assets included within map.

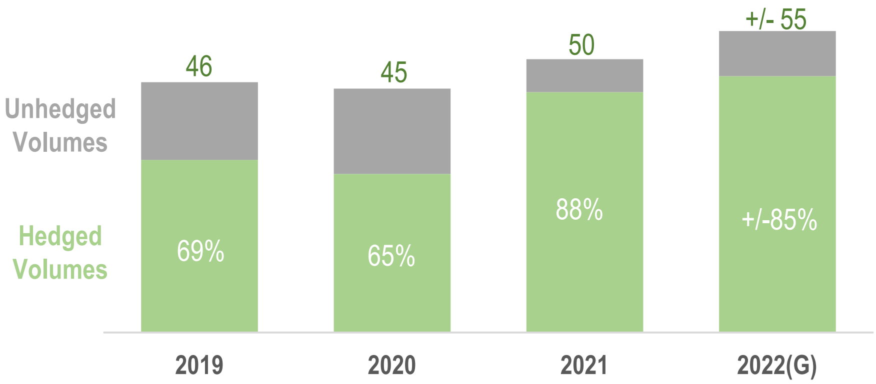
NGL Segment Frac Spread & Hedging Profile

C3+ Spec Product Sales Benefiting from East Gate Border Flows

NGL Total Sales *(Mb/d)*



C3+ Spec Product Sales(2) *(Mb/d)*

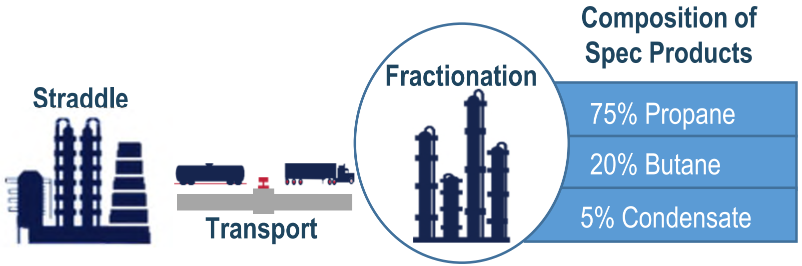


Hedging Profile (2019 – 2022(G))

(table data reflects full-year averages)	2019	2020	2021	2022(G)
NGL Segment				
C3+ Spec Product Sales(2) (mb/d)	46	45	50	+/- 55
% of C3+ Sales Hedged(3)	69%	65%	88%	+/- 85%

+/- 55Mb/d Benefit from Frac Spread

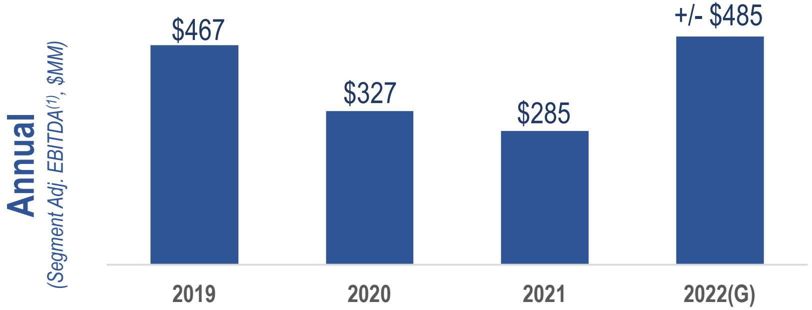
(+/- 85% of 2022 volumes hedged)

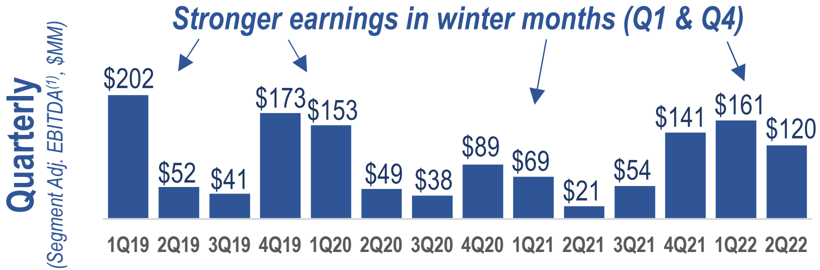


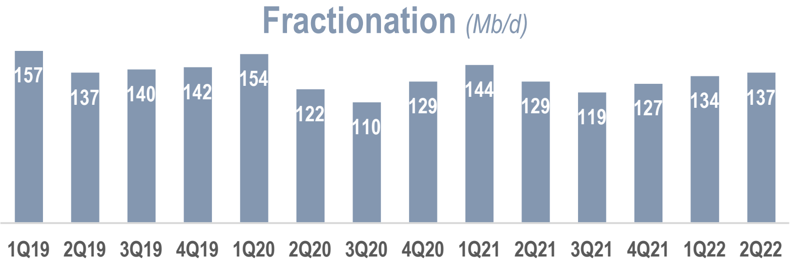
2022(G): Furnished August 3, 2022. (1) Decrease in sales from 2019 to 2020 a result of elimination of low margin spot business and asset dispositions. (2) C3+ sales on this slide refers to the sale of spec C3, C4 and C5+ exposed to frac spread. (3) Annual Frac spread volume hedged as a percentage of total C3+ volume produced / forecasted that is exposed to frac spread.

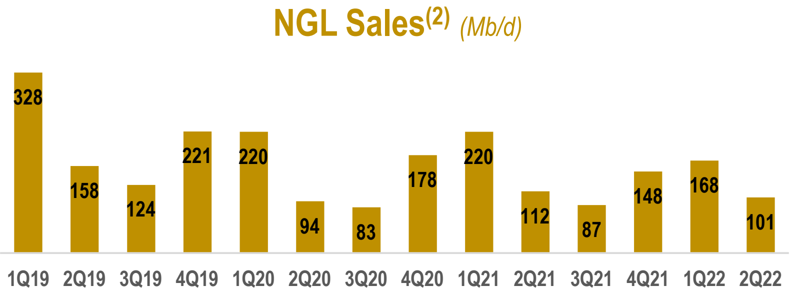
NGL Segment Detailed Data (2019 – 2022)

- **NGL Segment Considerations / Context:**
  - ~$175MM in non-core asset sales since 2019
  - Seasonally stronger demand / sales in winter months
  - Frac spread hedging & 3rd party contracts helps improve predictability







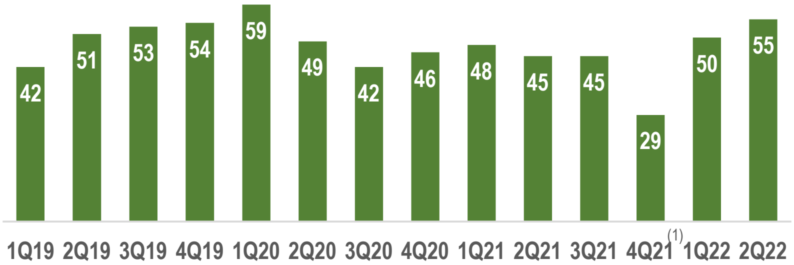


2022(G): Furnished August 3, 2022.
(1) See Definitions. (2) Decrease in sales from 2019 to 2020 a result of elimination of low margin spot business and asset dispositions.

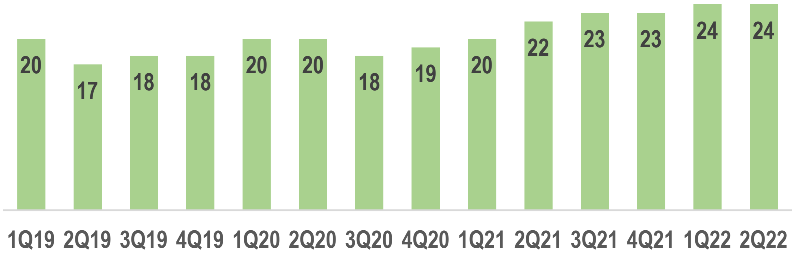
Additional NGL Detail: Fractionation Volumes by Asset

(Mb/d)

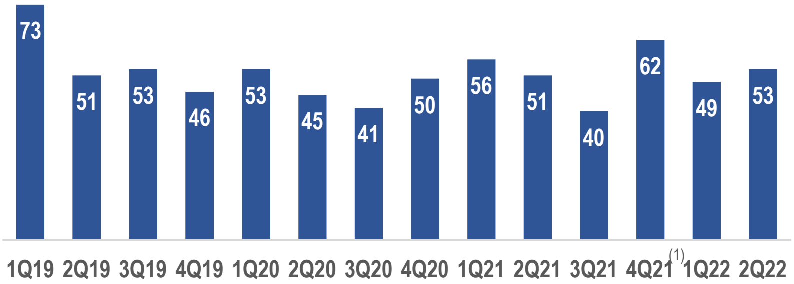
Fort Sask



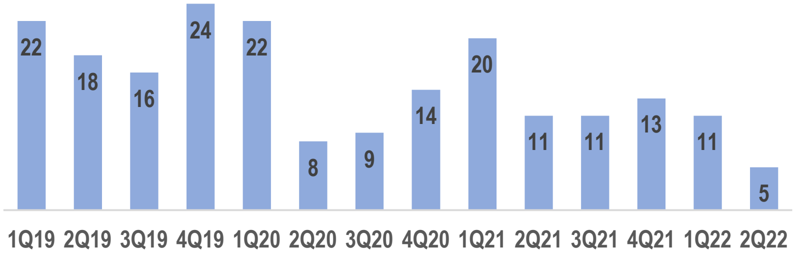
Empress



Sarnia



Other

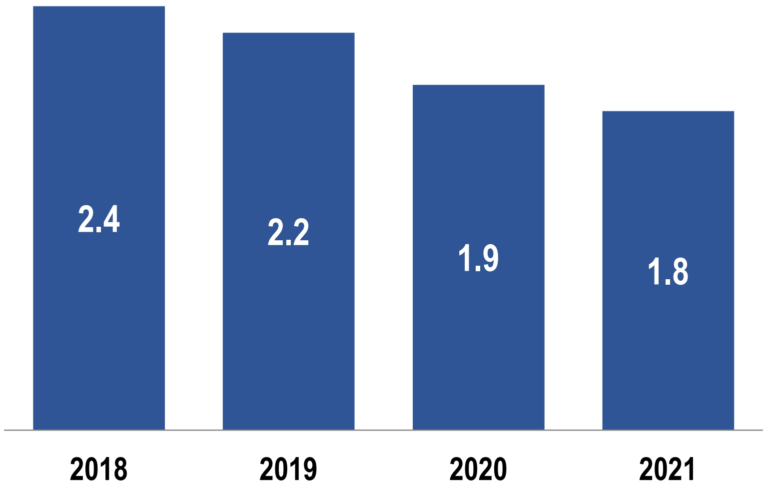


(1) Throughput volume impacted by Fort Sask Incident.

Plains 2021 Sustainability Report Highlights

- Establishment of Health, Safety, Environment and Sustainability (HSES) Board Committee
- Formation of multi-disciplinary Emerging Energy team focused on optimizing and aligning our assets with emerging opportunities
  - To date announced participation in ventures to explore low carbon hydrogen storage and install battery energy storage
- Continued efforts to achieve zero injuries and releases
  - Improved Safety & Environmental performance >50% & ~40% since 2017, respectively
- Active participation in standardizing industry ESG reporting with Energy Infrastructure Council (EIC) and API
- Publication of a Human Rights Policy
- Creation of a Code of Business Conduct for Contractors & Suppliers

Total Scope 1 + Scope 2 GHG Emissions[1] (mmt CO2e)



(1) Reflects emissions from assets operated for the full calendar year.

Free Cash Flow: Historical Detail

GAAP CFFO to Non-GAAP FCF

	2016	2017	2018	2019	2020	1Q21	2Q21	3Q21	4Q21	2021	1Q22	2Q22	YTD
Net Cash Provided by Op. Activities (GAAP)	$ 733	$ 2,499	$ 2,608	$ 2,504	$ 1,514	$ 791	$ 235	$ 336	$ 635	$ 1,996	$ 340	$ 792	$ 1,132
Net Cash (Used in) / Provided by Investing Activities	(1,273)	(1,570)	(813)	(1,765)	(1,093)	(108)	(175)	761	(92)	386	(81)	(42)	(123)
Cash Contributions from Noncontrolling Interests	-	-	-	-	12	1	-	-	-	1	-	-	-
Cash Distributions Paid to Noncontrolling Interests[(1)]	(4)	(2)	-	(6)	(10)	(6)	-	(4)	(4)	(14)	(59)	(62)	(121)
Sale of Noncontrolling Interest in a Sub	-	-	-	128	-	-	-	-	-	-	-	-	-
Free Cash Flow (non-GAAP)	**$ (544)**	**$ 927**	**$ 1,795**	**$ 861**	**$ 423**	**$ 678**	**$ 60**	**$ 1,093**	**$ 539**	**$ 2,369**	**$ 200**	**$ 688**	**$ 888**
Total Distributions[(2)]	(1,627)	(1,391)	(1,032)	(1,202)	(853)	(167)	(192)	(166)	(190)	(715)	(164)	(215)	(379)
FCF after Distributions (non-GAAP)	**$ (2,171)**	**$ (464)**	**$ 763**	**$ (341)**	**$ (430)**	**$ 511**	**$ (132)**	**$ 927**	**$ 349**	**$ 1,654**	**$ 36**	**$ 473**	**$ 509**

Expect to generate meaningful multi-year Free Cash Flow based on financial performance and continued capital discipline

(1) Cash distributions paid during the period presented.
(2) Cash distributions paid to our preferred and common unitholders during the period presented. The 2016 period also includes distributions paid to our general partner.

Management uses the non-GAAP financial measures Free Cash Flow ("FCF") and Free Cash Flow after Distributions ("FCFaD") to assess the amount of cash that is available for distributions, debt repayments, equity repurchases and other general partnership purposes. FCF is defined as net cash provided by operating activities, less net cash used in investing activities, which primarily includes acquisition, expansion and maintenance capital expenditures, investments in unconsolidated entities and the impact from the purchase and sale of linefill and base gas, net of proceeds from the sales of assets and further impacted by distributions to, contributions from and proceeds from the sale of noncontrolling interests. FCF is further reduced by cash distributions paid to preferred and common unitholders to arrive at FCF after Distributions.

Our definition and calculation of FCF may not be comparable to similarly-titled measures of other companies. FCF and FCF after Distributions are reconciled to net cash flows from operating activities, the most directly comparable measures as reported in accordance with GAAP, and should be viewed in addition to, and not in lieu of, our Consolidated Financial Statements and accompanying notes.

Condensed Consolidating Balance Sheet of Plains GP Holdings (PAGP)

	June 30, 2022			December 31, 2021		
	PAA	Consolidating Adjustments (1)	PAGP	PAA	Consolidating Adjustments (1)	PAGP
ASSETS						
Current assets	$ 6,661	$ 3	$ 6,664	$ 6,137	$ 3	$ 6,140
Property and equipment, net	14,673	4	14,677	14,903	6	14,909
Investments in unconsolidated entities	3,773	—	3,773	3,805	—	3,805
Intangible assets, net	1,839	—	1,839	1,960	—	1,960
Deferred tax asset	—	1,335	1,335	—	1,362	1,362
Linefill	931	—	931	907	—	907
Long-term operating lease right-of-use assets, net	365	—	365	393	—	393
Long-term inventory	378	—	378	253	—	253
Other long-term assets, net	266	—	266	251	(2)	249
Total assets	$ 28,886	$ 1,342	$ 30,228	$ 28,609	$ 1,369	$ 29,978
LIABILITIES AND PARTNERS' CAPITAL						
Current liabilities	$ 6,874	$ 2	$ 6,876	$ 6,232	$ 2	$ 6,234
Senior notes, net	7,933	—	7,933	8,329	—	8,329
Other long-term debt, net	53	—	53	69	—	69
Long-term operating lease liabilities	316	—	316	339	—	339
Other long-term liabilities and deferred credits	991	—	991	830	—	830
Total liabilities	16,167	2	16,169	15,799	2	15,801
Partners' capital excluding noncontrolling interests	9,931	(8,414)	1,517	9,972	(8,439)	1,533
Noncontrolling interests	2,788	9,754	12,542	2,838	9,806	12,644
Total partners' capital	12,719	1,340	14,059	12,810	1,367	14,177
Total liabilities and partners' capital	$ 28,886	$ 1,342	$ 30,228	$ 28,609	$ 1,369	$ 29,978

(1) Represents the aggregate consolidating adjustments necessary to produce consolidated financial statements for PAGP.

Definitions

- **Adjusted EBITDA:** adjusted earnings before interest, taxes, depreciation and amortization (Consolidated)
  - Attributable to PAA where noted; Segment Adjusted EBITDA by definition is attributable to PAA
- **Implied Distributable Cash Flow (DCF) Per Common Unit & Common Unit Equivalent (CUE):** Adjusted EBITDA (Consolidated) less interest expense net of certain non-cash items, maintenance capital, current income tax expense, investment capital of noncontrolling interests, distributions from unconsolidated entities in excess of/(less than) adjusted equity earnings, distributions to noncontrolling interests and preferred unit distributions paid adjusted for Series A preferred unit cash distributions paid, divided by the weighted average common units and common unit equivalents outstanding for the period
- **Cash Flow from Operations (CFFO):** Net Cash Provided by Operating Activities (GAAP)
- **Free Cash Flow (FCF):** net cash provided by operating activities (CFFO), less net cash used in investing activities, further impacted by distributions to, contributions from and proceeds from the sale of noncontrolling interests
- **Free Cash Flow after Distributions (FCFaD):** FCF further reduced by cash distributions paid to preferred and common unitholders
  - 2022(G) FCFaD assumes cash distribution per common unit paid in February and the increased annualized distribution rate of $0.87 per common unit for the remainder of the year.
- **CFFO, FCF & FCFaD** estimates do not factor in material, unforeseen changes in ST working capital (i.e. hedged inventory storage activities / volume / price / margin)
- **Leverage Ratio:** Total Debt plus 50% of PAA Preferred Securities less cash divided by LTM Adj. EBITDA attributable to PAA
- **Pipeline Volumes:** pipeline volumes associated with the Permian JV & Red River JV are presented on a consolidated (8/8ths) basis; all other volumes are presented net to our interest

2Q22 Earnings Call

August 3, 2022

PLAINS

Plains All American Reports Second-Quarter 2022 Results

Houston, TX – August 3, 2022 – Plains All American Pipeline, L.P. (Nasdaq: PAA) and Plains GP Holdings (Nasdaq: PAGP) today reported second-quarter 2022 results and provided the following updates:

- Second-quarter Net income attributable to PAA of $203 million and Net cash provided by operating activities of $792 million
- Second-quarter Adjusted EBITDA attributable to PAA of $615 million and increased guidance for full-year 2022 Adjusted EBITDA attributable to PAA by $100 million to +/- $2.375 billion
- Expect further deleveraging to achieve mid-point (4.0x) of targeted leverage range by year-end 2022 (previously expected year-end leverage of 4.25x)
- Increased 2022 Asset Sales target to +/- $200 million (+$100 million)
- Repurchased $49 million of common units during the quarter, bringing year-to-date repurchases to $74 million, and total repurchases since program inception to ~$300 million
- Completed $42 million (net to our interest, excludes customary closing adjustments) Permian Basin bolt-on acquisition of the remaining 50% ownership interest of the Advantage JV pipeline

"We delivered better than expected second-quarter results and increased our full-year 2022 Adjusted EBITDA guidance by an additional $100 million to plus or minus $2.375 billion, which is $175 million above our initial February guidance, enabling us to achieve the mid-point of our leverage target by year-end 2022, well ahead of our original expectations," stated Willie Chiang, Chairman and CEO of Plains. "Our increased guidance is driven by higher volumes and higher commodity prices in both our Crude Oil and NGL segments. We are well positioned to capture growing production, advance multiple optimization opportunities, and generate significant Free Cash Flow over the next several years, giving Plains increased financial flexibility and the ability to enhance cash returned to unitholders."

- more -

Plains All American Pipeline

Summary Financial Information (unaudited)
(in millions, except per unit data)

GAAP Results	Three Months Ended June 30, 2022	Three Months Ended June 30, 2021	% Change	Six Months Ended June 30, 2022	Six Months Ended June 30, 2021	% Change
Net income/(loss) attributable to PAA	$ 203	$ (220)	**	$ 390	$ 202	93 %
Diluted net income/(loss) per common unit	$ 0.22	$ (0.37)	**	$ 0.41	$ 0.14	193 %
Diluted weighted average common units outstanding	702	720	(3)%	703	721	(2)%
Net cash provided by operating activities	$ 792	$ 235	237 %	$ 1,132	$ 1,026	10 %
Distribution per common unit declared for the period	$ 0.2175	$ 0.18	21 %	$ 0.4350	$ 0.36	21 %

Non-GAAP Results [1]	Three Months Ended June 30, 2022	Three Months Ended June 30, 2021	% Change	Six Months Ended June 30, 2022	Six Months Ended June 30, 2021	% Change
Adjusted net income attributable to PAA	$ 260	$ 213	22 %	$ 526	$ 445	18 %
Diluted adjusted net income per common unit	$ 0.30	$ 0.23	30 %	$ 0.60	$ 0.48	25 %
Adjusted EBITDA	$ 704	$ 579	22 %	$ 1,394	$ 1,125	24 %
Adjusted EBITDA attributable to PAA [2]	$ 615	$ 575	7 %	$ 1,228	$ 1,118	10 %
Implied DCF per common unit and common unit equivalent	$ 0.57	$ 0.52	10 %	$ 1.13	$ 1.03	10 %
Free Cash Flow	$ 688	$ 60	**	$ 888	$ 738	20 %
Free Cash Flow after Distributions	$ 473	$ (132)	**	$ 509	$ 379	34 %

** Indicates that variance as a percentage is not meaningful.

(1) See the section of this release entitled "Non-GAAP Financial Measures and Selected Items Impacting Comparability" and the tables attached hereto for information regarding our Non-GAAP financial measures, including their reconciliation to the most directly comparable measures as reported in accordance with GAAP, and certain selected items that PAA believes impact comparability of financial results between reporting periods.

(2) Excludes amounts attributable to noncontrolling interests in the Plains Oryx Permian Basin LLC joint venture (the "Permian JV") and Red River Pipeline LLC.

333 Clay Street, Suite 1600 Houston, Texas 77002 713-646-4100 / 866-809-1291

Summary of Selected Financial Data by Segment (unaudited)
(in millions)

	Segment Adjusted EBITDA [1] [2]	
	Crude Oil	NGL
Three Months Ended June 30, 2022	$ 494	$ 120
Three Months Ended June 30, 2021	$ 553	$ 21
Percentage change in Segment Adjusted EBITDA versus 2021 period	***(11)%***	***471 %***
Percentage change in Segment Adjusted EBITDA versus 2021 period further adjusted for impact of divested assets [3]	***(8)%***	***471 %***

	Segment Adjusted EBITDA [1] [2]	
	Crude Oil	NGL
Six Months Ended June 30, 2022	$ 946	$ 281
Six Months Ended June 30, 2021	$ 1,027	$ 90
Percentage change in Segment Adjusted EBITDA versus 2021 period	***(8)%***	***212 %***
Percentage change in Segment Adjusted EBITDA versus 2021 period further adjusted for impact of divested assets [3]	***(3)%***	***212 %***

(1) During the fourth quarter of 2021, we modified our definition of Segment Adjusted EBITDA to exclude amounts attributable to noncontrolling interests. In connection with the Permian JV formation in October 2021, our Chief Operating Decision Maker (“CODM”) determined this modification resulted in amounts that were more meaningful to evaluate segment performance. Amounts for prior periods have been recast to reflect this modification.

(2) During the fourth quarter of 2021, we effected changes in the primary financial information provided to our CODM (our Chief Executive Officer) for assessing performance and allocating resources to present two operating segments, Crude Oil and NGL. Prior to the fourth quarter of 2021, this information was organized into three operating segments: Transportation, Facilities and Supply and Logistics. The change in our segments is reflective of a change in how our CODM views our business and stems primarily from (i) a multi-year transition in the midstream energy industry driven by increased competition that has reduced the stand alone earnings opportunities of our supply and logistics activities such that those activities now primarily support our effort to increase the utilization of our Crude Oil and NGL assets and (ii) internal changes regarding the oversight and reporting of our assets and related results of operations. All segment data and related disclosures for earlier periods presented herein have been recast to reflect the new segment reporting structure.

(3) Estimated impact of divestitures completed during 2021, assuming an effective date of January 1, 2021. Divested assets primarily included natural gas storage facilities previously included in our Crude Oil segment.

Second-quarter 2022 Crude Oil Segment Adjusted EBITDA decreased 11% versus comparable 2021 results primarily due to (i) the sale of our natural gas storage facilities in August of 2021 and (ii) the monetization of contango hedges that benefited the 2021 period. These items were partially offset by increased earnings in the second quarter of 2022 from higher tariff volumes on our pipelines and higher loss allowance revenue.

Second-quarter 2022 NGL Segment Adjusted EBITDA increased 471% versus comparable 2021 results primarily due to the favorable impact of higher realized fractionation spreads between the price of natural gas and the extracted NGL (“frac spreads”) and higher NGL sales prices, partially offset by lower NGL sales volumes.

Plains GP Holdings

PAGP owns an indirect non-economic controlling interest in PAA’s general partner and an indirect limited partner interest in PAA. As the control entity of PAA, PAGP consolidates PAA’s results into its financial statements, which is reflected in the condensed consolidating balance sheet and income statement tables attached hereto.

- more -

Conference Call

PAA and PAGP will hold a joint conference call at 4:30 p.m. CT on Wednesday, August 3, 2022 to discuss the following items:

1. PAA's second-quarter 2022 performance;
2. Capitalization and liquidity; and
3. Financial and operating guidance.

Conference Call Webcast Instructions

To access the internet webcast, please go to https://edge.media-server.com/mmc/p/5ttt3v92.

Alternatively, the webcast can be accessed on our website (www.plains.com) under Investor Relations (Navigate to: Investor Relations / either "PAA" or "PAGP" / News & Events / Quarterly Earnings). Following the live webcast, an audio replay in MP3 format will be available on our website within two hours after the end of the call and will be accessible for a period of 365 days. Slides will be posted prior to the call and a complete transcript will be posted after the call at the above referenced website.

Non-GAAP Financial Measures and Selected Items Impacting Comparability

To supplement our financial information presented in accordance with GAAP, management uses additional measures known as "non-GAAP financial measures" in its evaluation of past performance and prospects for the future and to assess the amount of cash that is available for distributions, debt repayments, common equity repurchases and other general partnership purposes. The primary additional measures used by management are Adjusted EBITDA, Adjusted EBITDA attributable to PAA, Implied distributable cash flow ("DCF"), Free Cash Flow and Free Cash Flow after Distributions.

Adjusted EBITDA is defined as earnings before interest, taxes, depreciation and amortization (including our proportionate share of depreciation and amortization, including write-downs related to cancelled projects, of unconsolidated entities), gains and losses on asset sales and asset impairments, goodwill impairment losses and gains on and impairments of investments in unconsolidated entities, adjusted for certain selected items impacting comparability. Our definition and calculation of certain non-GAAP financial measures may not be comparable to similarly-titled measures of other companies. Adjusted EBITDA, Adjusted EBITDA attributable to PAA, Implied DCF and certain other non-GAAP financial performance measures are reconciled to Net Income, and Free Cash Flow and Free Cash Flow after Distributions are reconciled to Net Cash Provided by Operating Activities (the most directly comparable measures as reported in accordance with GAAP) for the historical periods presented in the tables attached to this release, and should be viewed in addition to, and not in lieu of, our Condensed Consolidated Financial Statements and accompanying notes. In addition, we encourage you to visit our website at www.plains.com (in particular the section under "Financial Information" entitled "Non-GAAP Reconciliations" within the Investor Relations tab), which presents a reconciliation of our commonly used non-GAAP and supplemental financial measures. We do not reconcile non-GAAP financial measures on a forward-looking basis as it is impractical to do so without unreasonable effort.

Performance Measures

Management believes that the presentation of Adjusted EBITDA, Adjusted EBITDA attributable to PAA and Implied DCF provides useful information to investors regarding our performance and results of operations because these measures, when used to supplement related GAAP financial measures, (i) provide additional information about our core operating performance and ability to fund distributions to our unitholders through cash generated by our operations and (ii) provide investors with the same financial analytical framework upon which management bases financial, operational, compensation and planning/budgeting decisions. We also present these and additional non-GAAP financial measures, including adjusted net income attributable to PAA and basic and diluted adjusted net income per common unit, as they are measures that investors, rating agencies and debt holders have indicated are useful in assessing us and our results of operations. These non-GAAP measures may exclude, for example, (i) charges for obligations that are expected to be settled with the issuance of equity instruments, (ii) gains and losses on derivative instruments that are related to underlying activities in another period (or the reversal of such adjustments from a prior period), gains and losses on derivatives that are either related to investing activities (such as the purchase of linefill) or purchases of long-term inventory, and inventory valuation adjustments, as applicable, (iii) long-term inventory costing adjustments, (iv) items that are not indicative of our core operating results and/or (v) other items that we believe should be excluded in understanding our core operating performance. These measures may be further adjusted to include amounts related to deficiencies associated with minimum volume commitments whereby we have billed the counterparties for their deficiency obligation and such amounts are recognized as deferred revenue in “Other current liabilities” in our Condensed Consolidated Financial Statements. We also adjust for amounts billed by our equity method investees related to deficiencies under minimum volume commitments. All such amounts are presented net of applicable amounts subsequently recognized into revenue. Furthermore, the calculation of these measures contemplates tax effects as a separate reconciling item, where applicable. We have defined all such items as “selected items impacting comparability.” Due to the nature of the selected items, certain selected items impacting comparability may impact certain non-GAAP financial measures, referred to as adjusted results, but not impact other non-GAAP financial measures. We do not necessarily consider all of our selected items impacting comparability to be non-recurring, infrequent or unusual, but we believe that an understanding of these selected items impacting comparability is material to the evaluation of our operating results and prospects.

Although we present selected items impacting comparability that management considers in evaluating our performance, you should also be aware that the items presented do not represent all items that affect comparability between the periods presented. Variations in our operating results are also caused by changes in volumes, prices, exchange rates, mechanical interruptions, acquisitions, divestitures, investment capital projects and numerous other factors. These types of variations may not be separately identified in this release, but will be discussed, as applicable, in management’s discussion and analysis of operating results in our Quarterly Report on Form 10-Q.

Liquidity Measures

Management also uses the non-GAAP financial measures Free Cash Flow and Free Cash Flow after Distributions to assess the amount of cash that is available for distributions, debt repayments, common equity repurchases and other general partnership purposes. Free Cash Flow is defined as Net Cash Provided by Operating Activities, less Net Cash Used in Investing Activities, which primarily includes acquisition, investment and maintenance capital expenditures, investments in unconsolidated entities and the impact from the purchase and sale of linefill and base gas, net of proceeds from the sales of assets and further impacted by cash received from or paid to noncontrolling interests. Free Cash Flow is further reduced by cash distributions paid to our preferred and common unitholders to arrive at Free Cash Flow after Distributions.

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(in millions, except per unit data)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2022	2021	2022	2021
REVENUES	$ 16,359	$ 9,930	$ 30,053	$ 18,313
COSTS AND EXPENSES				
Purchases and related costs	15,324	9,277	28,109	16,669
Field operating costs	307	252	653	471
General and administrative expenses	78	72	160	139
Depreciation and amortization	242	196	473	374
(Gains)/losses on asset sales and asset impairments, net	(3)	369	(46)	370
Total costs and expenses	15,948	10,166	29,349	18,023
OPERATING INCOME/(LOSS)	411	(236)	704	290
OTHER INCOME/(EXPENSE)				
Equity earnings in unconsolidated entities	104	33	201	121
Interest expense, net	(99)	(107)	(206)	(213)
Other income/(expense), net	(118)	84	(155)	23
INCOME/(LOSS) BEFORE TAX	298	(226)	544	221
Current income tax expense	(30)	(1)	(48)	(3)
Deferred income tax (expense)/benefit	(17)	11	(20)	(11)
NET INCOME/(LOSS)	251	(216)	476	207
Net income attributable to noncontrolling interests	(48)	(4)	(86)	(5)
NET INCOME/(LOSS) ATTRIBUTABLE TO PAA	$ 203	$ (220)	$ 390	$ 202
NET INCOME/(LOSS) PER COMMON UNIT:				
Net income/(loss) allocated to common unitholders — Basic and Diluted	$ 153	$ (269)	$ 290	$ 103
Basic and diluted weighted average common units outstanding	702	720	703	721
Basic and diluted net income/(loss) per common unit	$ 0.22	$ (0.37)	$ 0.41	$ 0.14

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

CONDENSED CONSOLIDATED BALANCE SHEET DATA

(in millions)

	June 30, 2022	December 31, 2021
ASSETS		
Current assets (including Cash and cash equivalents of $267 and $449, respectively)	$ 6,661	$ 6,137
Property and equipment, net	14,673	14,903
Investments in unconsolidated entities	3,773	3,805
Intangible assets, net	1,839	1,960
Linefill	931	907
Long-term operating lease right-of-use assets, net	365	393
Long-term inventory	378	253
Other long-term assets, net	266	251
Total assets	$ 28,886	$ 28,609
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities	$ 6,874	$ 6,232
Senior notes, net	7,933	8,329
Other long-term debt, net	53	69
Long-term operating lease liabilities	316	339
Other long-term liabilities and deferred credits	991	830
Total liabilities	16,167	15,799
Partners' capital excluding noncontrolling interests	9,931	9,972
Noncontrolling interests	2,788	2,838
Total partners' capital	12,719	12,810
Total liabilities and partners' capital	$ 28,886	$ 28,609

DEBT CAPITALIZATION RATIOS

(in millions)

	June 30, 2022	December 31, 2021
Short-term debt	$ 630	$ 822
Long-term debt	7,986	8,398
Total debt	$ 8,616	$ 9,220
Long-term debt	$ 7,986	$ 8,398
Partners' capital excluding noncontrolling interests	9,931	9,972
Total book capitalization excluding noncontrolling interests ("Total book capitalization")	$ 17,917	$ 18,370
Total book capitalization, including short-term debt	$ 18,547	$ 19,192
Long-term debt-to-total book capitalization	45%	46%
Total debt-to-total book capitalization, including short-term debt	46%	48%

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

COMPUTATION OF BASIC AND DILUTED NET INCOME/(LOSS) PER COMMON UNIT [1]
(in millions, except per unit data)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2022	2021	2022	2021
Basic and Diluted Net Income/(Loss) per Common Unit				
Net income/(loss) attributable to PAA	$ 203	$ (220)	$ 390	$ 202
Distributions to Series A preferred unitholders	(37)	(37)	(74)	(74)
Distributions to Series B preferred unitholders	(12)	(12)	(25)	(25)
Other	(1)	—	(1)	—
Net income/(loss) allocated to common unitholders	$ 153	$ (269)	$ 290	$ 103
Basic and diluted weighted average common units outstanding [2] [3]	702	720	703	721
Basic and diluted net income/(loss) per common unit	$ 0.22	$ (0.37)	$ 0.41	$ 0.14

(1) We calculate net income/(loss) allocated to common unitholders based on the distributions pertaining to the current period's net income/(loss). After adjusting for the appropriate period's distributions, the remaining undistributed earnings or excess distributions over earnings, if any, are allocated to common unitholders and participating securities in accordance with the contractual terms of our partnership agreement in effect for the period and as further prescribed under the two-class method.

(2) The possible conversion of our Series A preferred units was excluded from the calculation of diluted net income/(loss) per common unit for the three and six months ended June 30, 2022 and 2021 as the effect was antidilutive.

(3) Our equity-indexed compensation plan awards that contemplate the issuance of common units are considered dilutive unless (i) they become vested only upon the satisfaction of a performance condition and (ii) that performance condition has yet to be satisfied. Equity-indexed compensation plan awards that are deemed to be dilutive are reduced by a hypothetical common unit repurchase based on the remaining unamortized fair value, as prescribed by the treasury stock method in guidance issued by the FASB. For the three and six months ended June 30, 2022 and 2021, the effect of equity-indexed compensation plan awards was antidilutive, or did not change the presentation of diluted weighted average common units outstanding or diluted net income/(loss) per common unit.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

NON-GAAP RECONCILIATIONS

COMPUTATION OF BASIC AND DILUTED ADJUSTED NET INCOME PER COMMON UNIT [1]

(in millions, except per unit data)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2022	2021	2022	2021
Basic and Diluted Adjusted Net Income per Common Unit				
Net income attributable to PAA	$ 203	$ (220)	$ 390	$ 202
Selected items impacting comparability - Adjusted net income attributable to PAA [2]	57	433	136	243
Adjusted net income attributable to PAA	$ 260	$ 213	$ 526	$ 445
Distributions to Series A preferred unitholders	(37)	(37)	(74)	(74)
Distributions to Series B preferred unitholders	(12)	(12)	(25)	(25)
Other	(1)	(1)	(2)	(1)
Adjusted net income allocated to common unitholders	$ 210	$ 163	$ 425	$ 345
Basic and diluted weighted average common units outstanding [3] [4]	702	720	703	721
Basic and diluted adjusted net income per common unit	$ 0.30	$ 0.23	$ 0.60	$ 0.48

[1] We calculate adjusted net income allocated to common unitholders based on the distributions pertaining to the current period's net income. After adjusting for the appropriate period's distributions, the remaining undistributed earnings or excess distributions over earnings, if any, are allocated to the common unitholders and participating securities in accordance with the contractual terms of our partnership agreement in effect for the period and as further prescribed under the two-class method.

[2] Certain of our non-GAAP financial measures may not be impacted by each of the selected items impacting comparability. See the "Selected Items Impacting Comparability" table for additional information.

[3] The possible conversion of our Series A preferred units was excluded from the calculation of diluted net income per common unit for the three and six months ended June 30, 2022 and 2021 as the effect was antidilutive.

[4] Our equity-indexed compensation plan awards that contemplate the issuance of common units are considered dilutive unless (i) they become vested only upon the satisfaction of a performance condition and (ii) that performance condition has yet to be satisfied. Equity-indexed compensation plan awards that are deemed to be dilutive are reduced by a hypothetical common unit repurchase based on the remaining unamortized fair value, as prescribed by the treasury stock method in guidance issued by the FASB. For the three and six months ended June 30, 2022 and 2021, the effect of equity-indexed compensation plan awards was antidilutive, or did not change the presentation of diluted weighted average common units outstanding or diluted adjusted net income per common unit.

Net Income/(Loss) Per Common Unit to Adjusted Net Income Per Common Unit Reconciliation:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2022	2021	2022	2021
Basic and diluted net income/(loss) per common unit	$ 0.22	$ (0.37)	$ 0.41	$ 0.14
Selected items impacting comparability per common unit [1]	0.08	0.60	0.19	0.34
Basic and diluted adjusted net income per common unit	$ 0.30	$ 0.23	$ 0.60	$ 0.48

[1] See the "Selected Items Impacting Comparability" and the "Computation of Basic and Diluted Adjusted Net Income Per Common Unit" tables for additional information.

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

NON-GAAP RECONCILIATIONS (continued)
(in millions, except per unit and ratio data)
Net Income/(Loss) to Adjusted EBITDA attributable to PAA and Implied DCF Reconciliation:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2022	2021	2022	2021
Net Income/(Loss)	$ 251	$ (216)	$ 476	$ 207
Interest expense, net	99	107	206	213
Income tax expense	47	(10)	68	14
Depreciation and amortization	242	196	473	374
(Gains)/losses on asset sales and asset impairments, net	(3)	369	(46)	370
Depreciation and amortization of unconsolidated entities [(1)]	17	68	37	88
Selected items impacting comparability - Adjusted EBITDA [(2)]	51	65	180	(141)
Adjusted EBITDA	$ 704	$ 579	$ 1,394	$ 1,125
Adjusted EBITDA attributable to noncontrolling interests	(89)	(4)	(166)	(7)
Adjusted EBITDA attributable to PAA	$ 615	$ 575	$ 1,228	$ 1,118
Adjusted EBITDA	$ 704	$ 579	$ 1,394	$ 1,125
Interest expense, net of certain non-cash items [(3)]	(97)	(101)	(199)	(202)
Maintenance capital	(43)	(37)	(70)	(73)
Investment capital of noncontrolling interests [(4)]	(15)	—	(30)	—
Current income tax expense	(30)	(1)	(48)	(3)
Distributions from unconsolidated entities in excess of/(less than) adjusted equity earnings [(5)]	5	(5)	(26)	1
Distributions to noncontrolling interests [(6)]	(62)	—	(121)	(6)
Implied DCF	$ 462	$ 435	$ 900	$ 842
Preferred unit distributions paid [(6)]	(62)	(62)	(99)	(99)
Implied DCF Available to Common Unitholders	$ 400	$ 373	$ 801	$ 743
Weighted Average Common Units Outstanding	702	720	703	721
Weighted Average Common Units and Common Unit Equivalents	773	791	774	792
Implied DCF per Common Unit [(7)]	$ 0.57	$ 0.52	$ 1.14	$ 1.03
Implied DCF per Common Unit and Common Unit Equivalent [(8)]	$ 0.57	$ 0.52	$ 1.13	$ 1.03
Cash Distribution Paid per Common Unit	$ 0.2175	$ 0.18	$ 0.3975	$ 0.36
Common Unit Cash Distributions [(6)]	$ 153	$ 130	$ 280	$ 260
Common Unit Distribution Coverage Ratio	2.61x	2.87x	2.86x	2.86x
Implied DCF Excess	$ 247	$ 243	$ 521	$ 483

(1) Adjustment to exclude our proportionate share of depreciation and amortization expense (including write-downs related to cancelled projects) of unconsolidated entities.

(2) See the "Selected Items Impacting Comparability" table for additional information.

(3) Excludes certain non-cash items impacting interest expense such as amortization of debt issuance costs and terminated interest rate swaps.

(4) Investment capital expenditures attributable to noncontrolling interests that reduce Implied DCF available to PAA common unitholders. Period is missing in proof

(5) Comprised of cash distributions received from unconsolidated entities less equity earnings in unconsolidated entities (adjusted for our proportionate share of depreciation and amortization, including write-downs related to cancelled projects, and selected items impacting comparability of unconsolidated entities).

(6) Cash distributions paid during the period presented.

(7) Implied DCF Available to Common Unitholders for the period divided by the weighted average common units outstanding for the period. Period is missing in proof

(8) Implied DCF Available to Common Unitholders for the period, adjusted for Series A preferred unit cash distributions paid, divided by the weighted average common units and common unit equivalents outstanding for the period. Our Series A preferred units are convertible into common units, generally on a one-for-one basis and subject to customary anti-dilution adjustments, in whole or in part, subject to certain minimum conversion amounts.

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

NON-GAAP RECONCILIATIONS (continued)

Net Income/(Loss) Per Common Unit to Implied DCF Per Common Unit and Common Unit Equivalent Reconciliation:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2022	2021	2022	2021
Basic net income/(loss) per common unit	$ 0.22	$ (0.37)	$ 0.41	$ 0.14
Reconciling items per common unit (1) (2)	0.35	0.89	0.73	0.89
Implied DCF per common unit	$ 0.57	$ 0.52	$ 1.14	$ 1.03
Basic net income/(loss) per common unit	$ 0.22	$ (0.37)	$ 0.41	$ 0.14
Reconciling items per common unit and common unit equivalent (1) (3)	0.35	0.89	0.72	0.89
Implied DCF per common unit and common unit equivalent	$ 0.57	$ 0.52	$ 1.13	$ 1.03

(1) Represents adjustments to Net Income/(Loss) to calculate Implied DCF Available to Common Unitholders. See the "Net Income/(Loss) to Adjusted EBITDA attributable to PAA and Implied DCF Reconciliation" table for additional information.

(2) Based on weighted average common units outstanding for the period of 702 million, 720 million, 703 million and 721 million, respectively.

(3) Based on weighted average common units outstanding for the period, as well as weighted average Series A preferred units outstanding of 71 million for each of the periods presented.

Free Cash Flow and Free Cash Flow after Distributions Reconciliation (1):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2022	2021	2022	2021
Net cash provided by operating activities	$ 792	$ 235	$ 1,132	$ 1,026
Adjustments to reconcile net cash provided by operating activities to free cash flow:				
Net cash used in investing activities	(42)	(175)	(123)	(283)
Cash contributions from noncontrolling interests	—	—	—	1
Cash distributions paid to noncontrolling interests (2)	(62)	—	(121)	(6)
Free Cash Flow	$ 688	$ 60	$ 888	$ 738
Cash distributions (3)	(215)	(192)	(379)	(359)
Free Cash Flow after Distributions	$ 473	$ (132)	$ 509	$ 379

(1) Management uses the Non-GAAP financial liquidity measures Free Cash Flow and Free Cash Flow after Distributions to assess the amount of cash that is available for distributions, debt repayments, common equity repurchases and other general partnership purposes.

(2) Cash distributions paid during the period presented.

(3) Cash distributions paid to preferred and common unitholders during the period.

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

SELECTED ITEMS IMPACTING COMPARABILITY

(in millions)

	Three Months Ended June 30, 2022	Three Months Ended June 30, 2021	Six Months Ended June 30, 2022	Six Months Ended June 30, 2021
Selected Items Impacting Comparability: (1)				
Gains/(losses) from derivative activities and inventory valuation adjustments (2)	$ (28)	$ (86)	$ (160)	$ 44
Long-term inventory costing adjustments (3)	13	27	105	68
Deficiencies under minimum volume commitments, net (4)	(10)	(6)	(15)	26
Equity-indexed compensation expense (5)	(7)	(4)	(15)	(9)
Net gain/(loss) on foreign currency revaluation (6)	(19)	7	(10)	15
Line 901 incident (7)	—	—	(85)	—
Significant transaction-related expenses (8)	—	(3)	—	(3)
Selected items impacting comparability - Adjusted EBITDA	$ (51)	$ (65)	$ (180)	$ 141
Gains from derivative activities	4	—	4	—
Gains/(losses) on asset sales and asset impairments, net	3	(369)	46	(370)
Tax effect on selected items impacting comparability	(13)	1	(6)	(14)
Selected items impacting comparability - Adjusted net income attributable to PAA	$ (57)	$ (433)	$ (136)	$ (243)

(1) Certain of our non-GAAP financial measures may not be impacted by each of the selected items impacting comparability. See the “Net Income to Adjusted EBITDA attributable to PAA and Implied DCF Reconciliation” and “Computation of Basic and Diluted Adjusted Net Income Per Common Unit” table for additional details on how these selected items impacting comparability affect such measures.

(2) We use derivative instruments for risk management purposes and our related processes include specific identification of hedging instruments to an underlying hedged transaction. Although we identify an underlying transaction for each derivative instrument we enter into, there may not be an accounting hedge relationship between the instrument and the underlying transaction. In the course of evaluating our results of operations, we identify differences in the timing of earnings from the derivative instruments and the underlying transactions and exclude the related gains and losses in determining adjusted results such that the earnings from the derivative instruments and the underlying transactions impact adjusted results in the same period. In addition, we exclude gains and losses on derivatives that are related to (i) investing activities, such as the purchase of linefill, and (ii) purchases of long-term inventory. We also exclude the impact of corresponding inventory valuation adjustments, as applicable.

(3) We carry crude oil and NGL inventory that is comprised of minimum working inventory requirements in third-party assets and other working inventory that is needed for our commercial operations. We consider this inventory necessary to conduct our operations and we intend to carry this inventory for the foreseeable future. Therefore, we classify this inventory as long-term on our balance sheet and do not hedge the inventory with derivative instruments (similar to linefill in our own assets). We treat the impact of changes in the average cost of the long-term inventory (that result from fluctuations in market prices) and write-downs of such inventory that result from price declines as a selected item impacting comparability.

(4) We, and certain of our equity method investments, have certain agreements that require counterparties to deliver, transport or throughput a minimum volume over an agreed upon period. Substantially all of such agreements were entered into with counterparties to economically support the return on capital expenditure necessary to construct the related asset. Some of these agreements include make-up rights if the minimum volume is not met. We, or our equity method investees, record a receivable from the counterparty in the period that services are provided or when the transaction occurs, including amounts for deficiency obligations from counterparties associated with minimum volume commitments. If a counterparty has a make-up right associated with a deficiency, we, or our equity method investees, defer the revenue attributable to the counterparty’s make-up right and subsequently recognize the revenue at the earlier of when the deficiency volume is delivered or shipped, when the make-up right expires or when it is determined that the counterparty’s ability to utilize the make-up right is remote. We include the impact of amounts billed to counterparties for their deficiency obligation, net of applicable amounts subsequently recognized into revenue or equity earnings, as a selected item impacting comparability. We believe the inclusion of the contractually committed revenues associated with that period is meaningful to investors as the related asset has been constructed, is standing ready to provide the committed service and the fixed operating costs are included in the current period results.

(5) Our total equity-indexed compensation expense includes expense associated with awards that will be settled in units and awards that will be settled in cash. The awards that will be settled in units are included in our diluted net income per unit calculation when the applicable performance criteria have been met. We consider the compensation expense associated with these awards as a selected item impacting comparability as the dilutive impact of the outstanding awards is included in our diluted net income per unit calculation, as applicable. The portion of compensation expense associated with awards that will be settled in cash is not considered a selected item impacting comparability.

(6) During the periods presented, there were fluctuations in the value of the Canadian dollar to the U.S. dollar, resulting in the realization of foreign exchange gains and losses on the settlement of foreign currency transactions as well as the revaluation of monetary assets and liabilities denominated in a foreign currency. These gains and losses are not integral to our core operating performance and were thus classified as a selected item impacting comparability.

(7) Includes costs recognized during the period related to the Line 901 incident that occurred in May 2015, net of amounts we believe are probable of recovery from insurance.

(8) Includes expenses associated with the Permian Basin joint venture transaction announced in July 2021.

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

SELECTED FINANCIAL DATA BY SEGMENT
(in millions)

	Three Months Ended June 30, 2022		Three Months Ended June 30, 2021	
	Crude Oil	**NGL**	**Crude Oil**	**NGL**
Revenues [1]	$ 15,940	$ 570	$ 9,779	$ 230
Purchases and related costs [1]	(15,163)	(312)	(9,127)	(229)
Field operating costs [2]	(233)	(74)	(203)	(49)
Segment general and administrative expenses [2] [3]	(59)	(19)	(54)	(18)
Equity earnings in unconsolidated entities	104	—	33	—
Adjustments: [4]				
Depreciation and amortization of unconsolidated entities	17	—	68	—
(Gains)/losses from derivative activities and inventory valuation adjustments	(29)	(46)	76	87
Long-term inventory costing adjustments	(13)	—	(27)	—
Deficiencies under minimum volume commitments, net	10	—	6	—
Equity-indexed compensation expense	7	—	4	—
Net (gain)/loss on foreign currency revaluation	2	1	(1)	—
Significant transaction-related expenses	—	—	3	—
Adjusted EBITDA attributable to noncontrolling interests [5]	(89)	—	(4)	—
Segment Adjusted EBITDA [6]	$ 494	$ 120	$ 553	$ 21
Maintenance capital	$ 25	$ 18	$ 23	$ 14

(1) Includes intersegment amounts.

(2) Field operating costs and Segment general and administrative expenses include equity-indexed compensation expense.

(3) Segment general and administrative expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments. The proportional allocations by segment require judgment by management and are based on the business activities that exist during each period.

(4) Represents adjustments utilized by our CODM in the evaluation of segment results. Many of these adjustments are also considered selected items impacting comparability when calculating consolidated non-GAAP financial measures such as Adjusted EBITDA. See the "Selected Items Impacting Comparability" table for additional discussion.

(5) Reflects amounts attributable to noncontrolling interests in the Permian JV (beginning October 2021) and Red River Pipeline LLC.

(6) During the fourth quarter of 2021, we modified our definition of Segment Adjusted EBITDA to exclude amounts attributable to noncontrolling interests. In connection with the Permian JV formation in October 2021, our CODM determined this modification resulted in amounts that were more meaningful to evaluate segment performance. Amounts attributable to noncontrolling interests for periods prior have been recast to reflect this modification.

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

SELECTED FINANCIAL DATA BY SEGMENT

(in millions)

	Six Months Ended June 30, 2022		Six Months Ended June 30, 2021	
	Crude Oil	NGL	Crude Oil	NGL
Revenues [1]	$ 29,019	$ 1,304	$ 17,632	$ 869
Purchases and related costs [1]	(27,556)	(823)	(16,174)	(683)
Field operating costs [2]	(515)	(138)	(368)	(103)
Segment general and administrative expenses [2] [3]	(122)	(38)	(104)	(35)
Equity earnings in unconsolidated entities	201	—	121	—
Adjustments: [4]				
Depreciation and amortization of unconsolidated entities	37	—	88	—
(Gains)/losses from derivative activities and inventory valuation adjustments	30	(17)	(83)	48
Long-term inventory costing adjustments	(98)	(7)	(62)	(6)
Deficiencies under minimum volume commitments, net	15	—	(26)	—
Equity-indexed compensation expense	15	—	9	—
Net (gain)/loss on foreign currency revaluation	1	—	(2)	—
Line 901 incident	85	—	—	—
Significant transaction-related expenses	—	—	3	—
Adjusted EBITDA attributable to noncontrolling interests [5]	(166)	—	(7)	—
Segment Adjusted EBITDA [6]	$ 946	$ 281	$ 1,027	$ 90
Maintenance capital	$ 45	$ 25	$ 52	$ 21

(1) Includes intersegment amounts.

(2) Field operating costs and Segment general and administrative expenses include equity-indexed compensation expense.

(3) Segment general and administrative expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments. The proportional allocations by segment require judgment by management and are based on the business activities that exist during each period.

(4) Represents adjustments utilized by our CODM in the evaluation of segment results. Many of these adjustments are also considered selected items impacting comparability when calculating consolidated non-GAAP financial measures such as Adjusted EBITDA. See the “Selected Items Impacting Comparability” table for additional discussion.

(5) Reflects amounts attributable to noncontrolling interests in the Permian JV (beginning October 2021) and Red River Pipeline LLC.

(6) During the fourth quarter of 2021, we modified our definition of Segment Adjusted EBITDA to exclude amounts attributable to noncontrolling interests. In connection with the Permian JV formation in October 2021, our CODM determined this modification resulted in amounts that were more meaningful to evaluate segment performance. Amounts attributable to noncontrolling interests for periods prior have been recast to reflect this modification.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

OPERATING DATA BY SEGMENT [1]

	Three Months Ended June 30,		Six Months Ended June 30,	
	2022	2021	2022	2021
Crude Oil Segment Volumes				
Crude oil pipeline tariff volumes (by region) [1]:				
Permian Basin [2]	5,434	4,189	5,324	3,972
South Texas / Eagle Ford [2]	338	314	352	317
Mid-Continent [2]	483	467	478	420
Gulf Coast	200	159	198	152
Rocky Mountain [2]	353	327	350	307
Western	284	256	259	246
Canada	325	294	328	305
Crude oil pipeline tariff volumes (average volumes in thousands of barrels per day) [1] [2]	7,417	6,006	7,289	5,719
Commercial crude oil storage capacity (average monthly volumes in millions of barrels) [2] [3]	72	73	72	73
Crude oil lease gathering purchases (average volumes in thousands of barrels per day) [1]	1,368	1,352	1,364	1,264
NGL Segment Volumes				
NGL fractionation (average volumes in thousands of barrels per day) [1]	137	129	136	136
NGL pipeline tariff volumes (average volumes in thousands of barrels per day) [1]	187	181	182	182
NGL sales (average volumes in thousands of barrels per day) [1]	101	112	134	165

(1) Average daily volumes calculated as the total volumes (attributable to our interest for pipelines owned by unconsolidated entities or undivided joint interests) for the period divided by the number of days in the period. Volumes associated with acquisitions represent total volumes for the number of days we actually owned the assets divided by the number of days in the period.

(2) Includes volumes (attributable to our interest) from assets owned by unconsolidated entities.

(3) Average monthly capacity calculated as total volumes for the period divided by the number of months in the period.

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

NON-GAAP SEGMENT RECONCILIATIONS
(in millions)

Segment Adjusted EBITDA to Adjusted EBITDA attributable to PAA Reconciliation:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2022	2021	2022	2021
Crude Oil Segment Adjusted EBITDA	$ 494	$ 553	$ 946	$ 1,027
NGL Segment Adjusted EBITDA	120	21	281	90
Segment Adjusted EBITDA	$ 614	$ 574	$ 1,227	$ 1,117
Adjusted other income/(expense), net (1)	1	1	1	1
Adjusted EBITDA attributable to PAA (2)	$ 615	$ 575	$ 1,228	$ 1,118

(1) Represents "Other income/(expense), net" as reported on our Condensed Consolidated Statements of Operations, adjusted for selected items impacting comparability of $119 million and $(83) million for the three months ended June 30, 2022 and 2021, respectively and $156 million and $(22) million for the six months ended June 30, 2022 and 2021, respectively. See the "Selected Items Impacting Comparability" table for additional information. Adjusted other income/(expense), net attributable to noncontrolling interests is less than $1 million for each of the periods presented.

(2) See the "Net Income/(Loss) to Adjusted EBITDA attributable to PAA and Implied DCF Reconciliation" table for reconciliation to Net Income.

Reconciliation of Segment Adjusted EBITDA to Segment Adjusted EBITDA further adjusted for impact of divested assets:

	Three Months Ended June 30, 2022		Three Months Ended June 30, 2021	
	Crude Oil	NGL	Crude Oil	NGL
Segment Adjusted EBITDA	$ 494	$ 120	$ 553	$ 21
Impact of divested assets (1)	—	—	(18)	—
Segment Adjusted EBITDA further adjusted for impact of divested assets	$ 494	$ 120	$ 535	$ 21

	Six Months Ended June 30, 2022		Six Months Ended June 30, 2021	
	Crude Oil	NGL	Crude Oil	NGL
Segment Adjusted EBITDA	$ 946	$ 281	$ 1,027	$ 90
Impact of divested assets (1)	—	—	(53)	—
Segment Adjusted EBITDA further adjusted for impact of divested assets	$ 946	$ 281	$ 974	$ 90

(1) Estimated impact of divestitures completed during 2021, assuming an effective date of January 1, 2021. Divested assets primarily included natural gas storage facilities previously included in our Crude Oil segment. Note: The natural gas storage business captured one-time benefits from Winter Storm Uri in the first quarter 2021.

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PLAINS GP HOLDINGS AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS

(in millions, except per share data)

	Three Months Ended June 30, 2022			Three Months Ended June 30, 2021		
	PAA	Consolidating Adjustments [(1)]	PAGP	PAA	Consolidating Adjustments [(1)]	PAGP
REVENUES	$ 16,359	$ —	$ 16,359	$ 9,930	$ —	$ 9,930
COSTS AND EXPENSES						
Purchases and related costs	15,324	—	15,324	9,277	—	9,277
Field operating costs	307	—	307	252	—	252
General and administrative expenses	78	2	80	72	2	74
Depreciation and amortization	242	1	243	196	1	197
(Gains)/losses on asset sales and asset impairments, net	(3)	—	(3)	369	—	369
Total costs and expenses	15,948	3	15,951	10,166	3	10,169
OPERATING INCOME/(LOSS)	411	(3)	408	(236)	(3)	(239)
OTHER INCOME/(EXPENSE)						
Equity earnings in unconsolidated entities	104	—	104	33	—	33
Interest expense, net	(99)	—	(99)	(107)	—	(107)
Other income/(expense), net	(118)	—	(118)	84	—	84
INCOME/(LOSS) BEFORE TAX	298	(3)	295	(226)	(3)	(229)
Current income tax expense	(30)	—	(30)	(1)	—	(1)
Deferred income tax (expense)/benefit	(17)	(9)	(26)	11	7	18
NET INCOME/(LOSS)	251	(12)	239	(216)	4	(212)
Net (income)/loss attributable to noncontrolling interests	(48)	(160)	(208)	(4)	147	143
NET INCOME/(LOSS) ATTRIBUTABLE TO PAGP	$ 203	$ (172)	$ 31	$ (220)	$ 151	$ (69)
BASIC AND DILUTED WEIGHTED AVERAGE CLASS A SHARES OUTSTANDING			194			194
BASIC AND DILUTED NET INCOME/(LOSS) PER CLASS A SHARE			$ 0.16			$ (0.35)

(1) Represents the aggregate consolidating adjustments necessary to produce consolidated financial statements for PAGP.

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PLAINS GP HOLDINGS AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS

(in millions, except per share data)

	Six Months Ended June 30, 2022			Six Months Ended June 30, 2021		
	PAA	Consolidating Adjustments [1]	PAGP	PAA	Consolidating Adjustments [1]	PAGP
REVENUES	$ 30,053	$ —	$ 30,053	$ 18,313	$ —	$ 18,313
COSTS AND EXPENSES						
Purchases and related costs	28,109	—	28,109	16,669	—	16,669
Field operating costs	653	—	653	471	—	471
General and administrative expenses	160	3	163	139	3	142
Depreciation and amortization	473	2	475	374	1	375
(Gains)/losses on asset sales and asset impairments, net	(46)	—	(46)	370	—	370
Total costs and expenses	29,349	5	29,354	18,023	4	18,027
OPERATING INCOME	704	(5)	699	290	(4)	286
OTHER INCOME/(EXPENSE)						
Equity earnings in unconsolidated entities	201	—	201	121	—	121
Interest expense, net	(206)	—	(206)	(213)	—	(213)
Other income/(expense), net	(155)	—	(155)	23	—	23
INCOME BEFORE TAX	544	(5)	539	221	(4)	217
Current income tax expense	(48)	—	(48)	(3)	—	(3)
Deferred income tax expense	(20)	(23)	(43)	(11)	(22)	(33)
NET INCOME	476	(28)	448	207	(26)	181
Net income attributable to noncontrolling interests	(86)	(309)	(395)	(5)	(175)	(180)
NET INCOME ATTRIBUTABLE TO PAGP	$ 390	$ (337)	$ 53	$ 202	$ (201)	$ 1
BASIC AND DILUTED WEIGHTED AVERAGE CLASS A SHARES OUTSTANDING			194			194
BASIC AND DILUTED NET INCOME PER CLASS A SHARE			$ 0.27			$ —

(1) Represents the aggregate consolidating adjustments necessary to produce consolidated financial statements for PAGP.

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PLAINS GP HOLDINGS AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

CONDENSED CONSOLIDATING BALANCE SHEET DATA

(in millions)

	June 30, 2022			December 31, 2021		
	PAA	Consolidating Adjustments [1]	PAGP	PAA	Consolidating Adjustments [1]	PAGP
ASSETS						
Current assets	$ 6,661	$ 3	$ 6,664	$ 6,137	$ 3	$ 6,140
Property and equipment, net	14,673	4	14,677	14,903	6	14,909
Investments in unconsolidated entities	3,773	—	3,773	3,805	—	3,805
Intangible assets, net	1,839	—	1,839	1,960	—	1,960
Deferred tax asset	—	1,335	1,335	—	1,362	1,362
Linefill	931	—	931	907	—	907
Long-term operating lease right-of-use assets, net	365	—	365	393	—	393
Long-term inventory	378	—	378	253	—	253
Other long-term assets, net	266	—	266	251	(2)	249
Total assets	$ 28,886	$ 1,342	$ 30,228	$ 28,609	$ 1,369	$ 29,978
LIABILITIES AND PARTNERS' CAPITAL						
Current liabilities	$ 6,874	$ 2	$ 6,876	$ 6,232	$ 2	$ 6,234
Senior notes, net	7,933	—	7,933	8,329	—	8,329
Other long-term debt, net	53	—	53	69	—	69
Long-term operating lease liabilities	316	—	316	339	—	339
Other long-term liabilities and deferred credits	991	—	991	830	—	830
Total liabilities	16,167	2	16,169	15,799	2	15,801
Partners' capital excluding noncontrolling interests	9,931	(8,414)	1,517	9,972	(8,439)	1,533
Noncontrolling interests	2,788	9,754	12,542	2,838	9,806	12,644
Total partners' capital	12,719	1,340	14,059	12,810	1,367	14,177
Total liabilities and partners' capital	$ 28,886	$ 1,342	$ 30,228	$ 28,609	$ 1,369	$ 29,978

(1) Represents the aggregate consolidating adjustments necessary to produce consolidated financial statements for PAGP.

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PLAINS GP HOLDINGS AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

COMPUTATION OF BASIC AND DILUTED NET INCOME/(LOSS) PER CLASS A SHARE [1]

(in millions, except per share data)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2022	2021	2022	2021
Basic and Diluted Net Income/(Loss) per Class A Share				
Net income/(loss) attributable to PAGP	$ 31	$ (69)	$ 53	$ 1
Basic and diluted weighted average Class A shares outstanding	194	194	194	194
Basic and diluted net income/(loss) per Class A share	$ 0.16	$ (0.35)	$ 0.27	$ —

(1) For each of the three and six months ended June 30, 2022 and 2021, the possible exchange of AAP units and AAP Management units would not have had a dilutive effect on basic net income/(loss) per Class A share.

Forward-Looking Statements

Except for the historical information contained herein, the matters discussed in this release consist of forward-looking statements that involve certain risks and uncertainties that could cause actual results or outcomes to differ materially from results or outcomes anticipated in the forward-looking statements. These risks and uncertainties include, among other things, the following:

- general economic, market or business conditions in the United States and elsewhere (including the potential for a recession or significant slowdown in economic activity levels, the risk of persistently high inflation and continued supply chain issues, the impact of coronavirus variants on growth, and the timing, pace and extent of economic recovery) that impact demand for crude oil, drilling and production activities and therefore the demand for the midstream services we provide and commercial opportunities available to us;
- declines in global crude oil demand and crude oil prices (whether due to the COVID-19 pandemic, future pandemics or other factors) that correspondingly lead to a significant reduction of North American crude oil and NGL production (whether due to reduced producer cash flow to fund drilling activities or the inability of producers to access capital, or both, the unavailability of pipeline and/or storage capacity, the shutting-in of production by producers, government-mandated pro-ration orders, or other factors), which in turn could result in significant declines in the actual or expected volume of crude oil and NGL shipped, processed, purchased, stored, fractionated and/or gathered at or through the use of our assets and/or the reduction of commercial opportunities that might otherwise be available to us;
- fluctuations in refinery capacity in areas supplied by our mainlines and other factors affecting demand for various grades of crude oil and NGL and resulting changes in pricing conditions or transportation throughput requirements;
- unanticipated changes in crude oil and NGL market structure, grade differentials and volatility (or lack thereof);
- the effects of competition and capacity overbuild in areas where we operate, including contract renewal risk and the risk of loss of business to other midstream operators who are willing or under pressure to aggressively reduce transportation rates in order to capture or preserve customers;
- negative societal sentiment regarding the hydrocarbon energy industry and the continued development and consumption of hydrocarbons, which could influence consumer preferences and governmental or regulatory actions that adversely impact our business;
- environmental liabilities or events that are not covered by an indemnity, insurance or existing reserves;
- the occurrence of a natural disaster, catastrophe, terrorist attack (including eco-terrorist attacks) or other event that materially impacts our operations, including cyber or other attacks on our electronic and computer systems;

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- weather interference with business operations or project construction, including the impact of extreme weather events or conditions;
- the impact of current and future laws, rulings, governmental regulations, executive orders, trade policies, accounting standards and statements, and related interpretations, including legislation, executive orders or regulatory initiatives that prohibit, restrict or regulate hydraulic fracturing or that prohibit the development of oil and gas resources and the related infrastructure on lands dedicated to or served by our pipelines;
- loss of key personnel and inability to attract and retain new talent;
- disruptions to futures markets for crude oil, NGL and other petroleum products, which may impair our ability to execute our commercial or hedging strategies;
- the effectiveness of our risk management activities;
- shortages or cost increases of supplies, materials or labor;
- maintenance of our credit rating and ability to receive open credit from our suppliers and trade counterparties;
- tightened capital markets or other factors that increase our cost of capital or limit our ability to obtain debt or equity financing on satisfactory terms to fund additional acquisitions, investment capital projects, working capital requirements and the repayment or refinancing of indebtedness;
- the successful operation of joint ventures and joint operating arrangements we enter into from time to time, whether relating to assets operated by us or by third parties, and the successful integration and future performance of acquired assets or businesses;
- the availability of, and our ability to consummate, divestitures, joint ventures, acquisitions or other strategic opportunities;
- the refusal or inability of our customers or counterparties to perform their obligations under their contracts with us (including commercial contracts, asset sale agreements and other agreements), whether justified or not and whether due to financial constraints (such as reduced creditworthiness, liquidity issues or insolvency), market constraints, legal constraints (including governmental orders or guidance), the exercise of contractual or common law rights that allegedly excuse their performance (such as force majeure or similar claims) or other factors;
- our inability to perform our obligations under our contracts, whether due to non-performance by third parties, including our customers or counterparties, market constraints, third-party constraints, legal constraints (including governmental orders or guidance), or other factors or events;
- the incurrence of costs and expenses related to unexpected or unplanned capital expenditures, third-party claims or other factors;
- failure to implement or capitalize, or delays in implementing or capitalizing, on investment capital projects, whether due to permitting delays, permitting withdrawals or other factors;
- the amplification of other risks caused by volatile financial markets, capital constraints, liquidity concerns and inflation;
- the use or availability of third-party assets upon which our operations depend and over which we have little or no control;
- the currency exchange rate of the Canadian dollar to the United States dollar;
- inability to recognize current revenue attributable to deficiency payments received from customers who fail to ship or move more than minimum contracted volumes until the related credits expire or are used;
- significant under-utilization of our assets and facilities;
- increased costs, or lack of availability, of insurance;
- fluctuations in the debt and equity markets, including the price of our units at the time of vesting under our long-term incentive plans;

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- risks related to the development and operation of our assets; and
- other factors and uncertainties inherent in the transportation, storage, terminalling and marketing of crude oil, as well as in the processing, transportation, fractionation, storage and marketing of NGL as discussed in the Partnerships' filings with the Securities and Exchange Commission.

About Plains:

PAA is a publicly traded master limited partnership that owns and operates midstream energy infrastructure and provides logistics services for crude oil and natural gas liquids (NGL). PAA owns an extensive network of pipeline gathering and transportation systems, in addition to terminalling, storage, processing, fractionation and other infrastructure assets serving key producing basins, transportation corridors and major market hubs and export outlets in the United States and Canada. On average, PAA handles more than 7 million barrels per day of crude oil and NGL.

PAGP is a publicly traded entity that owns an indirect, non-economic controlling general partner interest in PAA and an indirect limited partner interest in PAA, one of the largest energy infrastructure and logistics companies in North America.

PAA and PAGP are headquartered in Houston, Texas. For more information, please visit www.plains.com.

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Second-Quarter 2022

PAA & PAGP

Non-GAAP & Supplemental Reconciliations

Non-GAAP Reconciliations and Supplemental Calculations: Table of Contents

Introduction

<u>Non-GAAP Financial Measures and Selected Items Impacting Comparability</u>

To supplement our financial information presented in accordance with GAAP, management uses additional measures known as “non-GAAP financial measures” in its evaluation of past performance and prospects for the future and to assess the amount of cash that is available for distributions, debt repayments, common equity repurchases and other general partnership purposes. The primary additional measures used by management are Adjusted EBITDA, Adjusted EBITDA attributable to PAA, Implied distributable cash flow (“DCF”), Free Cash Flow and Free Cash Flow after Distributions.

Adjusted EBITDA is defined as earnings before interest, taxes, depreciation and amortization (including our proportionate share of depreciation and amortization, including write-downs related to cancelled projects of unconsolidated entities), gains and losses on asset sales and asset impairments, goodwill impairment losses and gains on and impairments of investments in unconsolidated entities, adjusted for certain selected items impacting comparability. Our definition and calculation of certain non-GAAP financial measures may not be comparable to similarly-titled measures of other companies. Adjusted EBITDA, Adjusted EBITDA attributable to PAA, Implied DCF and certain other non-GAAP financial performance measures are reconciled to Net Income/(Loss), Free Cash Flow and Free Cash Flow after Distributions are reconciled to Net Cash Provided by Operating Activities, the most directly comparable measures as reported in accordance with GAAP, for the historical periods presented in the following pages, and should be viewed in addition to, and not in lieu of, our Consolidated Financial Statements in our Annual Reports on Form 10-K, our Condensed Consolidated Financial Statements in our Quarterly Reports on Form 10-Q and notes thereto. We do not provide a reconciliation of non-GAAP financial measures to the equivalent GAAP financial measures on a forward-looking basis as it is impractical to forecast certain items that we have defined as “Selected Items Impacting Comparability” without unreasonable effort, due to the uncertainty and inherent difficulty of predicting the occurrence and financial impact of and the periods in which such items may be recognized. Thus, a reconciliation of non-GAAP financial measures to the equivalent GAAP financial measures could result in disclosure that could be imprecise or potentially misleading.

Performance Measures

Management believes that the presentation of such additional financial measures provides useful information to investors regarding our performance and results of operations because these measures, when used to supplement related GAAP financial measures, (i) provide additional information about our core operating performance and ability to fund distributions to our unitholders through cash generated by our operations and (ii) provide investors with the same financial analytical framework upon which management bases financial, operational, compensation and planning/budgeting decisions. We also present these and additional non-GAAP financial measures, including adjusted net income attributable to PAA and basic and diluted adjusted net income per common unit, as they are measures that investors, rating agencies and debt holders have indicated are useful in assessing us and our results of operations. These non-GAAP measures may exclude, for example, (i) charges for obligations that are expected to be settled with the issuance of equity instruments, (ii) gains and losses on derivative instruments that are related to underlying activities in another period (or the reversal of such adjustments from a prior period), gains and losses on derivatives that are either related to investing activities (such as the purchase of linefill) or purchases of long-term inventory, and inventory valuation adjustments, as applicable, (iii) long-term inventory costing adjustments, (iv) items that are not indicative of our core operating results and/or (v) other items that we believe should be excluded in understanding our core operating performance. These measures may further be adjusted to include amounts related to deficiencies associated with minimum volume commitments whereby we have billed the counterparties for their deficiency obligation and such amounts are recognized as deferred revenue in “Other current liabilities” in our Consolidated Financial Statements in our Annual Reports on Form 10-K and our Condensed Consolidated Financial Statements in our Quarterly Reports on Form 10-Q. We also adjust for amounts billed by our equity method investees related to deficiencies under minimum volume commitments. All such amounts are presented net of applicable amounts subsequently recognized into revenue. Furthermore, the calculation of these measures contemplates tax effects as a separate reconciling item, where applicable. We have defined all such items as “selected items impacting comparability.” Due to the nature of the selected items, certain selected items impacting comparability may impact certain non-GAAP financial measures, referred to as adjusted results, but not impact other non-GAAP financial measures. We do not necessarily consider all of our selected items impacting comparability to be non-recurring, infrequent or unusual, but we believe that an understanding of these selected items impacting comparability is material to the evaluation of our operating results and prospects.

Although we present selected items impacting comparability that management considers in evaluating our performance, you should also be aware that the items presented do not represent all items that affect comparability between the periods presented. Variations in our operating results are also caused by changes in volumes, prices, exchange rates, mechanical interruptions, acquisitions, investment capital projects and numerous other factors and will be discussed, as applicable, in management’s discussion and analysis of operating results in our Quarterly Report on Form 10-Q and in our Annual Report on form 10-K for the period(s) applicable.

Liquidity Measures

Management also uses the non-GAAP financial measures Free Cash Flow and Free Cash Flow after Distributions to assess the amount of cash that is available for distributions, debt repayments, common equity repurchases and other general partnership purposes. Free Cash Flow is defined as Net Cash Provided by Operating Activities, less Net Cash Used in Investing Activities, which primarily includes acquisition, investment and maintenance capital expenditures, investments in unconsolidated entities and the impact from the purchase and sale of linefill and base gas, net of proceeds from the sales of assets and further impacted by cash received from or paid to noncontrolling interests. Free Cash Flow is further reduced by cash distributions paid to our preferred and common unitholders to arrive at Free Cash Flow after Distributions.

Reconciliation to Adjusted EBITDA and Adjusted Net Income Attributable to PAA (in millions) (1) (2)

Selected Items Impacting Comparability (3)

	2022			2021					2020					2019				
	Q1	Q2	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD
Gains/(losses) from derivative activities and inventory valuation adjustments	$ (132)	$ (28)	$ (160)	$ 131	$ (86)	$ (9)	$ 249	$ 285	$ (4)	$ (99)	$ (98)	$ (258)	$ (460)	$ 97	$ (51)	$ 30	$ (234)	$ (158)
Long-term inventory costing adjustments	92	13	105	41	27	13	13	94	(115)	51	(2)	21	(44)	21	(25)	1	22	20
Deficiencies under minimum volume commitments, net	(6)	(10)	(15)	32	(6)	(56)	38	7	2	(7)	(64)	(5)	(74)	7	(1)	4	8	18
Equity-indexed compensation expense	(7)	(7)	(15)	(5)	(4)	(6)	(5)	(19)	(4)	(5)	(5)	(5)	(19)	(3)	(4)	(5)	(4)	(17)
Net gain/(loss) on foreign currency revaluation	9	(19)	(10)	8	7	(18)	11	7	(46)	23	10	28	16	(4)	(8)	5	7	1
Significant transaction-related expenses	—	—	—	—	(3)	(2)	(11)	(16)	(3)	—	—	—	(3)	—	—	—	—	—
Line 901 incident	(85)	—	(85)	—	—	—	(15)	(15)	—	—	—	—	—	—	(10)	—	—	(10)
Net gain on early repayment of senior notes	—	—	—	—	—	—	—	—	—	3	—	—	3	—	—	—	—	—
Selected items impacting comparability - Adjusted EBITDA	$ (129)	$ (51)	$ (180)	$ 207	$ (65)	$ (78)	$ 280	$ 343	$ (170)	$ (34)	$ (159)	$ (219)	$ (581)	$ 118	$ (99)	$ 35	$ (201)	$ (146)
Gains/(losses) from derivative activities	—	4	4	—	—	—	—	—	—	—	—	—	—	—	(1)	—	—	(1)
Gain (loss) on/(impairment of) investments in unconsolidated entities, net	—	—	—	—	—	—	2	2	(22)	(69)	(91)	—	(182)	267	—	4	—	271
Gains/(losses) on asset sales and asset impairments, net	42	3	46	(2)	(369)	(221)	—	(592)	(619)	1	2	(101)	(719)	(4)	4	7	(34)	(28)
Goodwill impairment losses	—	—	—	—	—	—	—	—	(2,515)	—	—	—	(2,515)	—	—	—	—	—
Tax effect on selected items impacting comparability	8	(13)	(6)	(15)	1	32	(63)	(44)	23	11	9	31	76	24	(9)	(27)	24	12
Selected items impacting comparability - Adjusted net income attributable to PAA	$ (79)	$ (57)	$ (136)	$ 190	$ (433)	$ (267)	$ 219	$ (291)	$ (3,303)	$ (91)	$ (239)	$ (289)	$ (3,921)	$ 405	$ (105)	$ 19	$ (211)	$ 108

Net Income/(Loss) to Adjusted EBITDA attributable to PAA Reconciliation

	2022			2021					2020					2019				
	Q1	Q2	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD
Net Income/(Loss)	$ 225	$ 251	$ 476	$ 423	$ (216)	$ (55)	$ 497	$ 648	$ (2,845)	$ 144	$ 146	$ (25)	$ (2,580)	$ 970	$ 448	$ 454	$ 307	$ 2,180
Interest expense, net	107	99	206	107	107	106	106	425	108	108	113	108	436	101	103	108	114	425
Income tax expense/(benefit)	21	47	68	24	(10)	(30)	88	73	21	(12)	(3)	(26)	(19)	24	(23)	41	25	66
Depreciation and amortization	230	242	473	177	196	178	223	774	168	166	160	160	653	136	147	156	163	601
(Gains)/losses on asset sales and asset impairments, net	(42)	(3)	(46)	2	369	221	—	592	619	(1)	(2)	101	719	4	(4)	(7)	34	28
Goodwill impairment losses	—	—	—	—	—	—	—	—	2,515	—	—	—	2,515	—	—	—	—	—
(Gain on)/impairment of investments in unconsolidated entities, net	—	—	—	—	—	—	(2)	(2)	22	69	91	—	182	(267)	—	(4)	—	(271)
Depreciation and amortization of unconsolidated entities (4)	20	17	37	20	68	21	14	123	17	16	18	22	73	12	14	18	16	62
Selected items impacting comparability - Adjusted EBITDA	129	51	180	(207)	65	78	(280)	(343)	170	34	159	219	581	(118)	99	(35)	201	146
Adjusted EBITDA	$ 690	$ 704	$ 1,394	$ 546	$ 579	$ 519	$ 646	$ 2,290	$ 795	$ 524	$ 682	$ 559	$ 2,560	$ 862	$ 784	$ 731	$ 860	$ 3,237
Less: Adjusted EBITDA attributable to noncontrolling interests	(76)	(89)	(166)	(3)	(4)	(5)	(82)	(94)	(2)	(2)	(4)	(5)	(14)	—	(3)	(5)	(2)	(10)
Adjusted EBITDA attributable to PAA	$ 614	$ 615	$ 1,228	$ 543	$ 575	$ 514	$ 564	$ 2,196	$ 793	$ 522	$ 678	$ 554	$ 2,546	$ 862	$ 781	$ 726	$ 858	$ 3,227

Net Income/(Loss) to Adjusted Net Income Attributable to PAA Reconciliation

	2022			2021					2020					2019				
	Q1	Q2	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD
Net Income/(Loss)	$ 225	$ 251	$ 476	$ 423	$ (216)	$ (55)	$ 497	$ 648	$ (2,845)	$ 144	$ 146	$ (25)	$ (2,580)	$ 970	$ 448	$ 454	$ 307	$ 2,180
Less: Net income attributable to noncontrolling interests	(38)	(48)	(86)	(1)	(4)	(4)	(47)	(55)	(2)	(2)	(3)	(3)	(10)	—	(2)	(5)	(1)	(9)
Net income/(loss) attributable to PAA	187	203	390	422	(220)	(59)	450	593	(2,847)	142	143	(28)	(2,590)	970	446	449	306	2,171
Selected items impacting comparability - Adjusted net income attributable to PAA	79	57	136	(190)	433	267	(219)	291	3,303	91	239	289	3,921	(405)	105	(19)	211	(108)
Adjusted net income attributable to PAA	$ 266	$ 260	$ 526	$ 232	$ 213	$ 208	$ 231	$ 884	$ 456	$ 233	$ 382	$ 261	$ 1,331	$ 565	$ 551	$ 430	$ 517	$ 2,063

(1) Amounts may not recalculate due to rounding.
(2) Certain of our non-GAAP financial measures may not be impacted by each of the selected items impacting comparability.
(3) For more information regarding our Selected Items Impacting Comparability, please refer to our most recently issued PAA & PAGP Earnings Release.
(4) Adjustment to add back our proportionate share of depreciation and amortization expense (including write-downs related to cancelled projects) of unconsolidated entities.

PLAINS ALL AMERICAN PIPELINE, L.P.

Adjusted Net Income Per Common Unit (in millions, except per unit data) [1] [2]

Basic Adjusted Net Income Per Common Unit

	2022			2021					2020					2019
	Q1	Q2	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	YTD
Net income/(loss) attributable to PAA	$ 187	$ 203	$ 390	$ 422	$ (220)	$ (59)	$ 450	$ 593	$ (2,847)	$ 142	$ 143	$ (28)	$ (2,590)	$ 2,171
Selected items impacting comparability - Adjusted net income attributable to PAA [3]	79	57	136	(190)	433	267	(219)	291	3,303	91	239	289	3,921	(108)
Adjusted net income attributable to PAA	$ 266	$ 260	$ 526	$ 232	$ 213	$ 208	$ 231	$ 884	$ 456	$ 233	$ 382	$ 261	$ 1,331	$ 2,063
Distributions to Series A preferred unitholders [4]	(37)	(37)	(74)	(37)	(37)	(37)	(37)	(149)	(37)	(37)	(37)	(37)	(149)	(149)
Distributions to Series B preferred unitholders [4]	(12)	(12)	(25)	(12)	(12)	(12)	(12)	(49)	(12)	(12)	(12)	(12)	(49)	(49)
Other	(1)	(1)	(2)	(1)	(1)	(1)	(2)	(3)	(2)	(1)	(2)	(1)	(4)	(6)
Adjusted net income allocated to common unitholders	$ 216	$ 210	$ 425	$ 182	$ 163	$ 158	$ 180	$ 683	$ 405	$ 183	$ 331	$ 211	$ 1,129	$ 1,859
Basic weighted average common units outstanding	705	702	703	722	720	715	709	716	728	728	728	726	728	727
Basic adjusted net income per common unit	$ 0.31	$ 0.30	$ 0.60	$ 0.25	$ 0.23	$ 0.22	$ 0.25	$ 0.95	$ 0.56	$ 0.25	$ 0.46	$ 0.29	$ 1.55	$ 2.56

Diluted Adjusted Net Income Per Common Unit

	2022			2021					2020					2019
	Q1	Q2	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	YTD
Net income/(loss) attributable to PAA	$ 187	$ 203	$ 390	$ 422	$ (220)	$ (59)	$ 450	$ 593	$ (2,847)	$ 142	$ 143	$ (28)	$ (2,590)	$ 2,171
Selected items impacting comparability - Adjusted net income attributable to PAA [3]	79	57	136	(190)	433	267	(219)	291	3,303	91	239	289	3,921	(108)
Adjusted net income attributable to PAA	$ 266	$ 260	$ 526	$ 232	$ 213	$ 208	$ 231	$ 884	$ 456	$ 233	$ 382	$ 261	$ 1,331	$ 2,063
Distributions to Series A preferred unitholders [4]	(37)	(37)	(74)	(37)	(37)	(37)	(37)	(149)	—	(37)	(37)	(37)	(149)	—
Distributions to Series B preferred unitholders [4]	(12)	(12)	(25)	(12)	(12)	(12)	(12)	(49)	(12)	(12)	(12)	(12)	(49)	(49)
Other	(1)	(1)	(2)	(1)	(1)	(1)	(2)	(3)	(1)	(1)	(1)	(1)	(2)	(3)
Adjusted net income allocated to common unitholders	$ 216	$ 210	$ 425	$ 182	$ 163	$ 158	$ 180	$ 683	$ 443	$ 183	$ 332	$ 211	$ 1,131	$ 2,011
Basic weighted average common units outstanding	705	702	703	722	720	715	709	716	728	728	728	726	728	727
Effect of dilutive securities:														
Series A preferred units [5]	—	—	—	—	—	—	—	—	71	—	—	—	—	71
Equity-indexed compensation plan awards [6]	—	—	—	—	—	—	—	—	1	—	—	—	—	2
Diluted weighted average common units outstanding	705	702	703	722	720	715	709	716	800	728	728	726	728	800
Diluted adjusted net income per common unit	$ 0.31	$ 0.30	$ 0.60	$ 0.25	$ 0.23	$ 0.22	$ 0.25	$ 0.95	$ 0.55	$ 0.25	$ 0.46	$ 0.29	$ 1.55	$ 2.51

(1) Amounts may not recalculate due to rounding.
(2) We calculate adjusted net income allocated to common unitholders based on the distributions pertaining to the current period's net income (whether paid in cash or in-kind). After adjusting for the appropriate period's distributions, the remaining undistributed earnings or excess distributions over earnings, if any, are allocated to the common unitholders and participating securities in accordance with the contractual terms of our partnership agreement in effect for the period and as further prescribed under the two-class method.
(3) Certain of our non-GAAP financial measures may not be impacted by each of the selected items impacting comparability.
(4) Distributions pertaining to the period presented.
(5) For certain periods presented, the possible conversion of our Series A preferred units was excluded from the calculation of diluted adjusted net income per common unit as the effect was antidilutive or did not change the presentation of diluted adjusted net income per common unit.
(6) Our equity-indexed compensation plan awards that contemplate the issuance of common units are considered dilutive unless (i) they become vested only upon the satisfaction of a performance condition and (ii) that performance condition has yet to be satisfied. Equity-indexed compensation plan awards that are deemed to be dilutive are reduced by a hypothetical common unit repurchase based on the remaining unamortized fair value, as prescribed by the treasury stock method in guidance issued by the FASB. For certain periods presented, such equity-indexed compensation plan awards did not change the presentation of diluted weighted average common units outstanding or diluted adjusted net income per common unit.

Net Income/(Loss) Per Common Unit to Adjusted Net Income Per Common Unit Reconciliation [1]

Basic Adjusted Net Income Per Common Unit

	2022			2021					2020					2019
	Q1	Q2	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	YTD
Basic net income/(loss) per common unit	$ 0.19	$ 0.22	$ 0.41	$ 0.51	$ (0.37)	$ (0.15)	$ 0.56	$ 0.55	$ (3.98)	$ 0.13	$ 0.13	$ (0.11)	$ (3.83)	$ 2.70
Selected items impacting comparability per common unit [2]	0.12	0.08	0.19	(0.26)	0.60	0.37	(0.31)	0.40	4.54	0.12	0.33	0.40	5.38	(0.14)
Basic adjusted net income per common unit	$ 0.31	$ 0.30	$ 0.60	$ 0.25	$ 0.23	$ 0.22	$ 0.25	$ 0.95	$ 0.56	$ 0.25	$ 0.46	$ 0.29	$ 1.55	$ 2.56

Diluted Adjusted Net Income Per Common Unit

	2022			2021					2020					2019
	Q1	Q2	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	YTD
Diluted net income/(loss) per common unit	$ 0.19	$ 0.22	$ 0.41	$ 0.51	$ (0.37)	$ (0.15)	$ 0.56	$ 0.55	$ (3.98)	$ 0.13	$ 0.13	$ (0.11)	$ (3.83)	$ 2.65
Selected items impacting comparability per common unit [2]	0.12	0.08	0.19	(0.26)	0.60	0.37	(0.31)	0.40	4.53	0.12	0.33	0.40	5.38	(0.14)
Diluted adjusted net income per common unit	$ 0.31	$ 0.30	$ 0.60	$ 0.25	$ 0.23	$ 0.22	$ 0.25	$ 0.95	$ 0.55	$ 0.25	$ 0.46	$ 0.29	$ 1.55	$ 2.51

(1) Amounts may not recalculate due to rounding.
(2) For more information regarding our Selected Items Impacting Comparability, please refer to our most recently issued PAA & PAGP Earnings Release.

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PAA Credit Metrics (in millions, except ratio amounts)[1]

Debt Capitalization Ratios

	2022		2021				2020	2019
	As of March 31,	As of June 30,	As of March 31,	As of June 30,	As of September 30,	As of December 31,	As of December 31,	As of December 31,
Short-term debt	$ 900	$ 630	$ 254	$ 1,456	$ 808	$ 822	$ 831	$ 504
Senior notes, net	7,931	7,933	9,073	8,326	8,327	8,329	9,071	8,939
Other long-term debt, net	55	53	265	63	61	69	311	248
Long-term debt	7,986	7,986	9,338	8,389	8,388	8,398	9,382	9,187
Total debt	$ 8,886	$ 8,616	$ 9,592	$ 9,845	$ 9,196	$ 9,220	$ 10,213	$ 9,691
Long-term debt	$ 7,986	$ 7,986	$ 9,338	$ 8,389	$ 8,388	$ 8,398	$ 9,382	$ 9,187
Partners' capital excluding noncontrolling interests	10,043	9,931	9,943	9,495	9,152	9,972	9,593	13,062
Total book capitalization excluding noncontrolling interests ("Total book capitalization")	$ 18,029	$ 17,917	$ 19,281	$ 17,884	$ 17,540	$ 18,370	$ 18,975	$ 22,249
Total book capitalization, including short-term debt	$ 18,929	$ 18,547	$ 19,535	$ 19,340	$ 18,348	$ 19,192	$ 19,806	$ 22,753
Long-term debt-to-total book capitalization	44 %	45 %	48 %	47 %	48 %	46 %	49 %	41 %
Total debt-to-total book capitalization, including short-term debt	47 %	46 %	49 %	51 %	50 %	48 %	52 %	43 %

(1) Amounts may not recalculate due to rounding.

PLAINS ALL AMERICAN PIPELINE, L.P.

Implied Distributable Cash Flow (in millions, except per unit and ratio data)[1]

Implied Distributable Cash Flow Reconciliation

	Three Months Ended		YTD	Three Months Ended		YTD	Twelve Months Ended December 31,		
	Mar 31, 2022	Jun 30, 2022	Jun 30, 2022	Mar 31, 2021	Jun 30, 2021	Jun 30, 2021	2021	2020	2019
Adjusted EBITDA	$ 690	$ 704	$ 1,394	$ 546	$ 579	$ 1,125	$ 2,290	$ 2,560	$ 3,237
Interest expense, net of certain non-cash items [2]	(101)	(97)	(199)	(101)	(101)	(202)	(401)	(415)	(407)
Maintenance capital	(27)	(43)	(70)	(35)	(37)	(73)	(168)	(216)	(287)
Investment capital of noncontrolling interests [3]	(15)	(15)	(30)	—	—		(9)	—	—
Current income tax expense	(19)	(30)	(48)	(1)	(1)	(3)	(50)	(51)	(112)
Distributions from unconsolidated entities in excess of/(less than) adjusted equity earnings [4]	(31)	5	(26)	5	(5)	1	16	13	(49)
Distributions to noncontrolling interests [5]	(59)	(62)	(121)	(6)	—	(6)	(14)	(10)	(6)
Implied DCF	$ 438	$ 462	$ 900	$ 408	$ 435	842	$ 1,664	$ 1,881	$ 2,376
Preferred unit distributions paid [5]	(37)	(62)	(99)	(37)	(62)	(99)	(198)	(198)	(198)
Implied DCF available to common unitholders	$ 401	$ 400	$ 801	$ 371	$ 373	743	$ 1,466	$ 1,683	$ 2,178
Weighted average common units outstanding	705	702	703	722	720	721	716	728	727
Weighted average common units and common unit equivalents	776	773	774	793	791	792	787	799	798
Implied DCF per common unit [6]	$ 0.57	$ 0.57	$ 1.14	$ 0.51	$ 0.52	$ 1.03	$ 2.06	$ 2.31	$ 2.99
Implied DCF per common unit and common unit equivalent [7]	$ 0.56	$ 0.57	$ 1.13	$ 0.51	$ 0.52	$ 1.03	$ 2.06	$ 2.29	$ 2.91
Cash distribution paid per common unit	$ 0.18	$ 0.2175	$ 0.3975	$ 0.18	$ 0.18	$ 0.36	$ 0.72	$ 0.90	$ 1.38
Common unit cash distributions [5]	$ 127	$ 153	$ 280	$ 130	$ 130	$ 260	$ 517	$ 655	$ 1,004
Common unit distribution coverage ratio	3.16x	2.61x	2.86x	2.85x	2.87x	2.86x	2.85x	2.57x	2.17x
Implied DCF excess	$ 274	$ 247	$ 521	241	$ 243	$ 483	$ 949	$ 1,028	$ 1,174

(1) Amounts may not recalculate due to rounding.
(2) Excludes certain non-cash items impacting interest expense such as amortization of debt issuance costs and terminated interest rate swaps.
(3) Investment capital expenditures attributable to noncontrolling interests that reduce Implied DCF available to PAA common unitholders.
(4) Comprised of cash distributions received from unconsolidated entities less equity earnings in unconsolidated entities (adjusted for our proportionate share of depreciation and amortization, including write-downs related to cancelled projects, gains and losses on significant asset sales by such entities and selected items impacting comparability of unconsolidated entities).
(5) Cash distributions paid during the period presented.
(6) Implied DCF Available to Common Unitholders for the period divided by the weighted average common units outstanding for the period.
(7) Implied DCF Available to Common Unitholders for the period, adjusted for Series A preferred unit cash distributions paid, divided by the weighted average common units and common unit equivalents outstanding for the period. Our Series A preferred units are convertible into common units, generally on a one-for-one basis and subject to customary anti-dilution adjustments, in whole or in part, subject to certain minimum conversion amounts.

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Net Income/(Loss) Per Common Unit to Implied DCF Per Common Unit and Common Unit Equivalent Reconciliation [1] [2]

Implied DCF Per Common Unit

	Three Months Ended		YTD	Three Months Ended		YTD	Twelve Months Ended		
	Mar 31, 2022	Jun 30, 2022	Jun 30, 2022	Mar 31, 2021	Jun 30, 2021	Jun 30, 2021	Dec 31, 2021	Dec 31, 2020	Dec 31, 2019
Basic net income/(loss) per common unit	$ 0.19	$ 0.22	$ 0.41	$ 0.51	$ (0.37)	$ 0.14	$ 0.55	$ (3.83)	$ 2.70
Reconciling items per common unit	0.38	0.35	0.73	—	0.89	0.89	1.51	6.14	0.29
Implied DCF per common unit	$ 0.57	$ 0.57	$ 1.14	$ 0.51	$ 0.52	$ 1.03	$ 2.06	$ 2.31	$ 2.99

Implied DCF Per Common Unit and Common Unit Equivalent

	Three Months Ended		YTD	Three Months Ended		YTD	Twelve Months Ended		
	Mar 31, 2022	Jun 30, 2022	Jun 30, 2022	Mar 31, 2021	Jun 30, 2021	Jun 30, 2021	Dec 31, 2021	Dec 31, 2020	Dec 31, 2019
Basic net income/(loss) per common unit	$ 0.19	$ 0.22	$ 0.41	$ 0.51	$ (0.37)	$ 0.14	$ 0.55	$ (3.83)	$ 2.70
Reconciling items per common unit and common unit equivalent	0.37	0.35	0.72	—	0.89	0.89	1.51	6.12	0.21
Implied DCF per common unit and common unit equivalent	$ 0.56	$ 0.57	$ 1.13	$ 0.51	$ 0.52	$ 1.03	$ 2.06	$ 2.29	$ 2.91

(1) Amounts may not recalculate due to rounding.
(2) For information regarding our reconciliation of net income per common unit to Implied DCF per common unit and common unit equivalent, please refer to our latest issued PAA & PAGP Earnings Release.

PLAINS ALL AMERICAN PIPELINE, L.P.

Free Cash Flow (in millions): [1]

Free Cash Flow and Free Cash Flow after Distributions Reconciliation

	2022			2021					2020	2019
	Q1	Q2	YTD	Q1	Q2	Q3	Q4	YTD	YTD	YTD
Net cash provided by operating activities	$ 340	$ 792	$ 1,132	$ 791	$ 235	$ 336	$ 635	$ 1,996	$ 1,514	$ 2,504
Adjustments to reconcile net cash provided by operating activities to free cash flow:										
Net cash provided by/(used in) investing activities	(81)	(42)	(123)	(108)	(175)	761	(92)	386	(1,093)	(1,765)
Cash contributions from noncontrolling interests	—	—	—	1	—	—	—	1	12	—
Cash distributions paid to noncontrolling interests [2]	(59)	(62)	(121)	(6)	—	(4)	(4)	(14)	(10)	(6)
Sale of noncontrolling interest in a subsidiary	—	—	—	—	—	—	—	—	—	128
Free Cash Flow	$ 200	$ 688	$ 888	$ 678	$ 60	$ 1,093	$ 539	$ 2,369	$ 423	$ 861
Cash distributions [3]	(164)	(215)	(379)	(167)	(192)	(166)	(190)	(715)	(853)	(1,202)
Free Cash Flow after Distributions	$ 36	$ 473	$ 509	$ 511	$ (132)	$ 927	$ 349	$ 1,654	$ (430)	$ (341)

(1) Amounts may not recalculate due to rounding.
(2) Cash distributions paid during the period presented.
(3) Cash distributions paid to our preferred and common unitholders during the period presented.

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Segment Information (dollars in millions) [1] [2]

Segment Adjusted EBITDA [3]

	2022			2021					2020					2019				
	Q1	Q2	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD
Crude Oil Segment Adjusted EBITDA	$ 453	$ 494	$ 946	$ 474	$ 553	$ 459	$ 423	$ 1,909	$ 638	$ 472	$ 639	$ 465	$ 2,216	$ 659	$ 727	$ 681	$ 684	$ 2,753
NGL Segment Adjusted EBITDA	161	120	281	69	21	54	141	285	153	49	38	89	327	202	52	41	173	467
Segment Adjusted EBITDA	$ 614	$ 614	$ 1,227	$ 543	$ 574	$ 513	$ 564	$ 2,194	$ 791	$ 521	$ 677	$ 554	$ 2,543	$ 861	$ 779	$ 722	$ 857	$ 3,220
Adjusted other income/(expense), net [4]	—	1	1	—	1	1	—	2	2	1	1	—	3	1	2	4	1	7
Adjusted EBITDA attributable to PAA [5]	$ 614	$ 615	$ 1,228	$ 543	$ 575	$ 514	$ 564	$ 2,196	$ 793	$ 522	$ 678	$ 554	$ 2,546	$ 862	$ 781	$ 726	$ 858	$ 3,227

Segment Operational Information

	2022			2021					2020					2019				
	Q1	Q2	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD	Q1	Q2	Q3	Q4	YTD
Crude Oil Segment Volumes:																		
Crude oil pipeline tariff volumes (average volumes in thousands of barrels per day) [6][7]	7,159	7,417	7,289	5,430	6,006	6,162	7,202	6,205	6,974	5,656	5,868	5,835	6,082	6,201	6,522	6,807	6,911	6,613
Commercial crude oil storage capacity (average monthly volumes in millions of barrels) [7][8]	72	72	72	73	73	73	72	73	78	79	81	76	79	75	76	77	77	76
Crude oil lease gathering purchases (average volumes in thousands of barrels per day) [6]	1,361	1,368	1,364	1,174	1,352	1,372	1,419	1,330	1,318	1,077	1,147	1,155	1,174	1,128	1,102	1,146	1,271	1,162
NGL Segment Volumes:																		
NGL fractionation (average volumes in thousands of barrels per day) [6]	134	137	136	144	129	119	127	129	154	122	110	129	129	157	137	140	142	144
NGL pipeline tariff volumes (average volumes in thousands of barrels per day) [6]	176	187	182	183	181	165	189	179	187	194	180	177	184	210	182	193	184	192
NGL sales (average volumes in thousands of barrels per day) [6]	168	101	134	220	112	87	148	141	220	94	83	178	144	328	158	124	221	207

(1) Amounts may not recalculate due to rounding.
(2) During the fourth quarter of 2021, we reorganized our historical operating segments: Transportation, Facilities and Supply and Logistics into two operating segments: Crude Oil and Natural Gas Liquids ("NGL"). The change in our segments stems from several factors including, (i) a multi-year transition in the midstream energy industry driven by increased competition that has reduced the stand alone earnings opportunities of our supply and logistics activities such that those activities now function as a business development effort to help maximize the utilization of our Crude Oil and NGL assets and (ii) internal changes regarding the oversight and reporting of our assets and related results of operations. All segment data and related disclosures for earlier periods presented herein have been recast to reflect the new segment reporting structure.
(3) During the fourth quarter of 2021, we modified our definition of Segment Adjusted EBITDA to exclude amounts attributable to noncontrolling interests. In connection with the Plains Oryx Permian Basin joint venture formation in October 2021, our Chief Operating Decision Maker ("CODM") determined this modification resulted in amounts that were more meaningful to evaluate segment performance. Amounts for prior periods have been recast to reflect this modification.
(4) Represents "Other income/(expense), net" as reported on our Condensed Consolidated Statements of Operations, adjusted for selected items impacting comparability. See the "Selected Items Impacting Comparability" table for additional information. Adjusted other income/(expense), net attributable to noncontrolling interests is less than $1 million for each of the periods presented.
(5) See the "Net Income/(Loss) to Adjusted EBITDA attributable to PAA Reconciliation" table for reconciliation to Net Income/(Loss).
(6) Average daily volumes calculated as the total volumes (attributable to our interest for pipelines owned by unconsolidated entities or undivided joint interests) for the period divided by the number of days in the period. Volumes associated with acquisitions represent total volumes for the number of days we actually owned the assets divided by the number of days in the period.
(7) Includes volumes (attributable to our interest) from assets owned by unconsolidated entities.
(8) Average monthly capacity calculated as total volumes for the period divided by the number of months in the period.