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BDV Installation Criteria based on API 521

Mojtaba Habibi
Process Engineer at Petroleum Engineering and Development Company (PEDEC)
Top Contributor

Dears,

As you know API 521 is the most convenient reference for design of pressure relieving and depressuring systems.

There is an interesting statement at page 56 of API 521 - 2007 eidtion:

"Emergency depressuring for the fire scenario should be considered for large equipment operating at a gauge pressure of 1 700 kPa (approx. 250 psi) or higher.""

I am willing to know your experiences on this part of API 521?

In my view above statement is not conclusive. Reason being :

i) "Emergency depressuring for fire scenario..."
Does it mean equipment very unlikely to expose to fire will not govern by above statement ?

ii) "large equipment...".
How to define large equipment ? There is no quantitative statement to clearly classify it. A pressure vessel with 1000 barg may have small size but the risk is very high.

iii) "...pressure of 1700 or higher...".
A pressure vessel with 15 barg and large volume will have very big risk and consequence...

Let me know your idea and experiences.

Which BDV installation criteria do you follow? As I checked companies like TOTAL do not follow above mentioned API 521 criteria.

Many thanks for your time.

Best,
Mojtaba

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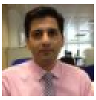

Saeid R. Mofrad
Principal Process Engineer at Petrofac (P.E.)
Top Contributor

Deciding which equipment needs to be depressuring facility depends on:

1. Equipment Condition
- Nature of Fluid (flammability, toxicity, explosion limit, etc)
- Pressure of fluid
- Quantity of fluid

and

2. Damage Mechanism
- Radiation impact (fire ball diameter, duration, radiation flux at 15m, injury or fatality level)
- Explosion impact (peak side-on overpressure, structure destruction, oil storage tank rupture, knockdown effect, fatal injury, etc)
- Missile impact (fragment damage radius, number of fragments, fragment kinetic energy)
- Environmental impact (VOC emission, toxic gas cloud, soil, water contamination, etc)

For example, the effect of failure of pressure vessel containing 10 m3 of natural gas at 10 barg may be tolerable while same at 17barg may not. It is because the mechanism of damage and the impact of this failure on people, asset, environment and reputation go beyond tolerable risk level.

The reason why big companies (mainly oil producers such as Shell, Total, BP, Exxon, etc) have their own criteria is that they have established the requirement based on the risk assessment which considers number of installation and employee they have, the money they have to pay in case of fatality/injury /production loss/ mechanical failure which can be summarized in one word “ALLOWABLE RISK”.

In short, the combination of all these parameters specifies the need for BDV and there is no single formula applicable to all conditions.
For example, when the risk analysis reveals that there is likelihood 1fatality/100 year. This results in totally different actual risk when it is going to be used a basis for design of 20 plants and operating staff of around 10,000 than single installation where 1000 people work. This is just the effect of the size of company on such requirement.

That is why you see shell DEP dictates this requirement for a system containing more than 4 m3 of C4 or lighter hydrocarbon (say LPG) whereas 2 tons of liquefied gases (gas/liquid) is used by Total.

In line with this, we have already equipped a pressure vessel designed for 10 barg (operating at about 4.0 barg) containing highly toxic components with depressuring facility just because of environmental impact of equipment failure.

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Learn Syan Lee likes this

Mojtaba

Mojtaba Habibi
Process Engineer at Petroleum Engineering and Development Company (PEDEC)
Top Contributor

Dear Saeid,

The main problem is that API 521 is the most convenient standard for design of depressuring systems and most of the clients (as per my limited working experience all of the clients I have seen) ask for design of depressring systems based on API 521 while as discussed above this is neither a complete nor a clear reference.

For example for the case you have mentioned (pressure vessel designed for 10 barg (operating at about 4.0 barg) containing highly toxic components), you should not provide BDV based on client request to design depressuring system based on API 521 while based on your company knowledge an experience you should.

So could you please shed some lights that how to resolve this conflict?

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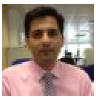

Saeid R. Mofrad
Principal Process Engineer at Petrofac (P.E.)
Top Contributor

API has already responded to this query when in states that:

The following should be considered when designing/specifying the depressurization system:

> Rupture time (time to escape, time for rescue actions)
> Rupture pressure of vessels (escalation, fragmentation)
> Rupture pressure of pipes (escalation)
> Total release of flammables (escalation)
> Instantaneous release rate (sudden increase in fire size during evacuation or rescue)
> Loss of production, reputation and rebuild cost
> Damage to internals of equipment (e.g. trays, packing supports), entrainment of packing or catalyst into the depressurization system, brittle failure due to cooling

The above can vary from installation to installation, i.e. it may be different for a low-manned, remote installation compared to an installation located in populated areas; whether the fluid is LPG, gas or oil; whether the fluid is toxic or not, etc. It may also be different from one user to the other and from one country to another.

So API also leaves this to you, your Client, and your judgment and analysis on case to case basis.

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Mojtaba

Mojtaba Habibi

Process Engineer at Petroleum Engineering and Development Company (PEDEC)

Top Contributor

Dear Saeid,

API statement comprises two qualitative and quantitative parts.

The qualitative part is described by your nice explanation

The quantitative part states that:
"Emergency depressuring for the fire scenario should be considered for large equipment operating at a gauge pressure of 1700 kPa (approx. 250 psi) or higher."

I think if the designer leave these 2 parts as is, then this will be subjected to many discussions with client at meetings like P&ID review and Hazop. Client may ask for BDV based on qualitative part of API 521 statement.

So as the remedial solution do you agree to offer specific BDV installation criteria issued via documents like depressurization philosophy as first order of precendece for design of depressuring systems?

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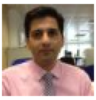

Saeid R. Mofrad

Principal Process Engineer at Petrofac (P.E.)

Top Contributor

Dear Mojtaba,

I believe even API statement ""Emergency depressuring for the fire scenario should be considered for large equipment operating at a gauge pressure of 1700 kPa (approx. 250 psi) or higher" is still very much qualitative. There are lots of words not clearly defined, "large", "approx", "or higher" (as you raised in the first post) :O)

I agree, this should be discussed with Client and recorded in depressuring philosophy. But don't educate Clients too much; they become a problem for you in future!
Write the philosophy based on what you feel is correct, get Client concurrence and go ahead!

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Sampath

Sampath Kumar R

Upstream Process Engineer at Technip

Dear Friends,

Interesting topic and discussion!!!

Even I had faced the similar problem regarding provision of BDV for a system. One of the ongoing projects which I am involved calls for BDV requirement as per the below statement:
"Remotely operable blowdown facilities shall be provided for all equipment containing pressurised hydrocarbons. Closed-in systems with a small inventory may be exempt from this if it is demonstrated that the consequences of not having a blowdown system cannot lead to incident escalation"

Above statement is quantitative and not clear about the BDV requirement and unfortunately we have not stated the API requirements in our Philosophy. Now the issue is extreme and client is asking BDV for remote wellhead platform's Test Separator. The justification given by client is that Test Separator contains pressurised hydrocarbons and requirement of BDV shall not be avoided. Still the problem is alive!!! (Would you provide some solution for this?)

Hence, as stated you, we need to write the Philosophy based on what we feel is correct (quantitative statement) and get the client concurrence at the initial stage.

Kind Regards

Sampath Kumar R

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S M

S M Kumar
Process Design Consultant
Top Contributor

Sampath: (1) Usually Test Sep is kept depressurised after a test. That means, Test Sep will remain depressurized most of the time. Check this out if this is true in your case. Talk to your client. (2) Your client is asking for remotely operable blowdown. Usually a Test Sep is provided a PCV to flare. If you have that then you should be able to remotely unload or open it - inch it in steps - to get what is required - remotely operated depressurization.

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Vishwanath

Vishwanath Raman
-Working as Senior Process Engineer in Petrofac

Dear Sampath
The requirement of BDV is dependent on company standards also.For example Statoil standards say if 1000 kg or more hydrocarbon is present in the system we require a BDV.So please see the clients standard.

regards
Vishwanath

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Sampath

Sampath Kumar R
Upstream Process Engineer at Technip

Dear Kumar Sir,

Thanks for the responses.

As you informed, normally test separators are depressurized after the well test. However, my client is keeping a case that during the testing if fire occurs, there should be an emergency depressurization (i.e.) automatic blowdown for test separator (being a pressurized hydrocarbon vessel).
In our case, test separator does not PCV and the depressurization activity is a manual operation.

Dear Vishwanath,
You are right that some companies will be very specific on blowdown requirement by indicating the volume as well as operating pressure criteria in which BDV is required. Whereas, our client requirement is qualitative and hence it’s difficult to close this issue.

Kind Regards

Sampath Kumar R

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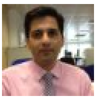

Saeid R. Mofrad
Principal Process Engineer at Petrofac (P.E.)
Top Contributor

Sampath,

I think you have to “demonstrate that the consequences of not having a blow down system cannot lead to incident escalation” as Client philosophy dictates. Otherwise you need depressuring facility.

Then, you have to see if there is any fire detection around test separator to trigger the automatic blow down or not. If not, you may be able to equip manual depressuring valve with actuator so that it can be operated remotely (from control room) because philosophy talks about“remotely operable blow down” not “remotely operable AUTOMATIC blow down”.

By the way, I feel the depressuring requirement for an offshore facility will be more stringent that onshore installation because of system compactness.

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Sampath

Sampath Kumar R
Upstream Process Engineer at Technip

Dear Saied,

As you correctly pointed out that Philosophy indicates “remotely operable blow down” not “remotely operable AUTOMATIC blow down”. This can be one of the points for discussion with client.

As per my understanding, the demonstration (qualitative) of not having blowdown shall be as follows:

1.Hydrocarbon liquid spillage around Test separator and nearby skid shall be cleaned before the testing operation is being carried out so that the possibility of pool fire will not occur.”

2.Test separator is intermediate operation and after each testing, this equipment shall be depressurized and drained completely.

I could not find other way to demonstrate apart from the above two points. Would you please share some thing, if you have anything better than this to demonstrate not to have blowdown?

Kind Regards

Sampath Kumar R

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S M

S M Kumar

Process Design Consultant

Top Contributor

Actuating a manual valve for remote opening to flare is the fastest way to move forward. Money is made in offshore projects by speed of execution.

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Vagif

Vagif Gafarov

Sr. Process Engineer at KBR

Well, to demonstrate that the blowdown is not necessary you can agree with the Client that the test separator will always operate at low pressure and/or imply the inherently safer design like tick walls etc.

BTW: the liquid spillage can occur from the test separator itself during the testing operation.

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